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Commissioner	:	Florio
Admin. Law Judge	:	Yip-Kikugawa
	:	

CONSUMER PROTECTION AND SAFETY DIVISION
CALIFORNIA PUBLIC UTILITIES COMMISSION

REVISED
REPORT AND TESTIMONY
OF
MARGARET FELTS

I.11-02-016

San Francisco, California
March 16, 2012

577551

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Soon, Appendices and other reference documents associated with the recordkeeping OII will be available on the Commission website. To access these documents, please visit http://www.cpuc.ca.gov/PUC/events/110224_sanbruno.htm, and search for the subject area called "Reference Documents for CPSD Reports in Recordkeeping Penalty Consideration Case".

1.0 INTRODUCTION

In the immediate aftermath of the 30" gas transmission line explosion in San Bruno on September 9, 2010, Pacific Gas and Electric Company (PG&E) told the National Transportation Safety Board (NTSB) it was a seamless pipe that had failed. PG&E based this statement on data from its electronic Geographic Information System (GIS), the primary source of information about the design and construction of its pipeline system. Of course, anyone viewing the remains of the pipe section lying on the ground in San Bruno could clearly see that the pipe had split along a longitudinal seam. This initial bit of bad data was only the tip of the iceberg.

On January 3, 2011, the NTSB issued several safety recommendations urging PG&E to search for all traceable and verifiable records to support the maximum allowable operating pressures it was using for its transmission lines. If PG&E could not find records, the NTSB recommended that PG&E hydrotest the lines to prove their integrity.[1] Immediately following receipt of the NTSB Advisory, the Executive Director of the California Public Utilities Commission (CPUC) ordered PG&E to comply with the NTSB recommendations, and on January 13, 2011 in its Resolution L-410, the CPUC ratified its Executive Director's order. The CPUC then instituted a formal investigation to determine whether PG&E violated any provision or provisions of the California Public Utilities Code, Commission general orders or decisions, or other applicable rules or requirements pertaining to safety recordkeeping for its gas service and facilities.[2]

This report considers PG&E's recordkeeping practices from an engineering perspective, focusing on two primary areas: 1) recordkeeping issues related to the September 9, 2010 San Bruno incident, and 2) recordkeeping issues related to the integrity management program and integrity management risk assessment model used to prioritize the replacement of pipe within PG&E's system.

2.0 RECORDS ISSUES RELATED TO LINE 132

This section highlights records related issues that can be tied directly or indirectly to the pipe failure and explosion at San Bruno on September 9, 2010. Some of the records issues are revisited in more detail in Sections 3.0 and 4.0 of this report. Those sections discuss PG&E's

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[1] NTSB Advisory to PG&E dated January 3,, 2011 (www.ntsbgov/doclib/recletters/2010/P-10-002-004.pdf).

[2] Order Instituting Investigation (OII) No. I.11-02-016, February 24, 2011.

integrity management program and risk assessment models and the data from records that is necessary to make such a risk assessment program fully functional.

2.1 Reused Pipe in Segment 180 of Line 132, Project GM 136471 in 1956

After the San Bruno incident, PG&E researched its records in an effort to determine the source of the failed pipe and produced to the NTSB a pieced together summary of new and reused pipe used in the installation of Segment 180.[3] However, after searching through all of its records, PG&E was still unable to identify records that documented the source of the one piece of pipe that failed.[4] If PG&E had kept orderly records of the purchase, installation, salvage, reconditioning, inspection, and reuse of pipe installed in its transmission system, PG&E would not have selected that piece of pipe for project GM 136471, because it did not meet PG&E's own specifications for high pressure transmission pipe.[5] NTSB lab results from thorough testing and inspection of the welds in the pipe section that failed at San Bruno show that the poor quality welds would have been visible to the naked eye.[6] Upon visual inspection, this piece of pipe would have been scrapped.

Without records about the source, specifications, or history of the pipe, it was possible for pipe to be salvaged, sent out to be re-wrapped and delivered to the construction site without anyone knowing or being able to observe the condition of the pipe.[7] The absence of pipe specification records and the absence of a tracking system for salvaged and reused pipe makes it impossible to determine if there are other pieces of pipe that do not meet minimum specifications for high pressure transmission line service installed elsewhere in Line 132.

2.2 The Maximum Operating Pressure for Line 132 Based on Historical Records – An Example of PG&E's Poor Recordkeeping Practices

During this investigation, PG&E produced voluminous historical records about its facilities and the operations of those facilities. The records were difficult to review because PG&E's record system lacks organization and many documents are missing. Over the course of this investigation, various records relating to the history of the Maximum Allowable Operating Pressure (MAOP) for

[3] Response to DR 3 Q 11 and NTSB_460802.

[4] NTSB_460802, p. 6.

[5] NTSB_460278, p. 4 and 10.

[6] NTSB Summary Report and NTSB 469689, NTSB Report, Office of Research and Engineering, Material Laboratory Division May 17, 2011, document no. 469689.

[7] Based on author's review of PG&E records in the ECTS database.

Line 132 were assembled in chronological order, extending from 1965 to present day. The MAOP history for Line 132 is set out in detail in this section and in more detail in Appendix 1.

PG&E's Standard Practice 1606, dated August 1965, shows the MAOP of line 132 to be 400 psi.[8] The MAOP for Line 132 remained set at 400 psi until 1976. PG&E appears to have based this MAOP on the grandfather clause, which allows an MAOP based on the highest operating pressure experienced between 1965 and 1970. PG&E documented a peak pressure of 400 psi for Line 132 in 1968.[9] However, as described below, there are numerous examples of PG&E's inconsistent positions about its MAOP for Line 132 in its records, which are compounded by the lack of any records explaining these discrepancies.

An internal PG&E letter dated August 15, 1978 says, "Information previously submitted by San Francisco Division regarding MAOP based on the highest operating pressure within the five year period prior to July 1, 1970, should be corrected in accordance with the attached listing."[10] The attached listing indicates that Line 132 MAOP should be corrected to 390 psig between Mile Posts (MP) 35.84 and 46.59, based on pressure readings on February 23, 1968. There is a footnote that says "date and highest operating pressure revised."[11] In association with this 1978 letter, the revised MAOP of 390 psi, was entered into the hand-written MAOP log for Line 132 between Mile Posts 35.84 and 46.59 and at the bottom of the official MAOP list, drawing 086868.[12] PG&E has produced two versions of the MAOP log. One is described in the preceding sentence. On the second version, someone lined out the entry of 390 psi and wrote "400 psi," adding a note, dated December 10, 2003, "See note – based on 10/16/68 & 10/28/68 Milpitas Term Records."[13] Thus, in 2003, PG&E edited its historical record for the period 1978 to 2003 regarding the MAOP on the section of pipeline between Mile Posts 35.84 and 46.59. A matching, hand written note appears on the 2003 revision 15 of Drawing 086868, which shows all of Line 132 at 390 psi. The note says "12/10/03 Have RCDS showing 400 psi btw 65 - 70."[14]

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8 P2-954

9 As discussed in Appendix 1, the authenticity of this record is questionable.

10 Response to DR 30 Q30, Supp Atch 2, p. 103.

11 Response to DR 30 Q30, Supp Atch 2, p. 104.

12 DR 30 Q 30 Supp Atch 3, p. 42 and P2-963, p. 4 note at bottom of page.

13 Response to DR 30 Q 30 Supp Atch 2, p. 102.

14 Response to OII_DR_5_Q9_Atch_4.

By its action in 1978 to lower the MAOP on one specific section of Line 132 PG&E redefined Line 132 into two sections. The first section runs from the Milpitas Terminal, which is Mile Post 1, to Mile Post 35.84. The MAOP for this first section was kept at 400 psi. The MAOP for the second section, between Mile Posts 35.84 and 46.59, was listed as 390 psi. The site of the 2010 San Bruno explosion is Segment 180 (MP 39.04 to MP 39.37) and, thus, is included in this second section.[15] From 1978 to 2003, the MAOP of Line 132, between Mile Posts 35.84 and 46.59, was documented in PG&E's records as 390 psi.

Confirming that PG&E did intend to differentiate MAOP data for the two sections of the pipeline, one MAOP binder includes a certification dated May 20, 1983, regarding the section of Line 132 from MP 1 to 35.84.[16] This certification is based on the highest pressure for a five-year period ending July 1, 1970.[17] A copy of the unsigned pressure log with the date of October 16, 1968 is attached to the memo.[18] Based on this record, it appears the basis for operating the section of Line 132 from MP 1 to MP 35.84 at an MAOP of 400 psig was a brief spike in Line 132 pressure to 400 psi in 1968.

PG&E originally tracked the Line 132 MAOP on a table that was Appendix A to Standard Practice 463.8.[19] In 1979, PG&E changed Appendix A to Drawing No. 086868.[20] In more recent years, PG&E has maintained the content of this table in an excel worksheet, but the final version is still maintained as Drawing 086868 (MAOP Drawing).[21] From 1979 until 1987 PG&E was updating the table about every 2 years. There were no updates between 1987 and 1998. In 1992 another internal PG&E letter states that the table is supposed to be updated annually and requests assistance in updating the MAOP data.[22] Other PG&E internal correspondence appears to show that updating this information lost priority within PG&E.[23]

[15] DR 30 Q 30 Supp Atch 2, p.102, SP463.8.

[16] DR 30 Q 30 Supp Atch 3, p. 43.

[17] By citing PG&E's certification based on the grandfather clause, CPSD does intend to imply that it agrees that a hydrotest was not required to establish the 400 psi MAOP for this section of L-132.

[18] DR 30 Q 30 Supp Atch 3, p. 45.

[19] P2-956 p. 6.

[20] P2-964.

[21] Response to DR 39 Q 12.

[22]Response to DR 30 Q 30 Atch 33, pp. 215 and 222.

[23] Response to DR 15 Q 1, including attachments.

Around 1997, updating Drawing 086868 prompted a series of actions that continued through 2010.[24] A list of Revision numbers and the changes made with each revision was kept from Rev. 14.1 through Rev. 20.[25] PG&E states that it did not retain any of the intermediate Revisions (i.e., 15.1-15.9, 16.1-16.5, 17.1-17.19, and 18.1-18.5), including 15.4, which is on the list of revision numbers with the notation: "Updated Line 132 MAOP to 400 psig, RTA 12/10/03 in handwriting that matches the note found on the historical MAOP log that was edited."[26]

PG&E did not file a request with the CPUC to uprate the MAOP of the second section of Line 132 from 390 psi to 400 psi.[27] It appears that, by 2003, the underlying records that define the historical identification of two sections of Line 132 had been lost. The 2003 statements refer to Line 132 as if the same MAOP should apply to the entire line. When PG&E was asked why the Pipeline Survey Sheets showed an MAOP of 390 psig, it responded:

> "Pursuant to 49 C.F.R. § 192.619, the MAOP on Line 132 was established at 400 psig based on pressure records maintained by the San Jose Division during the period between July 1, 1965 and July 1, 1970.
>
> The design pressure of 400 psig on Line 132 is based on these records and the Company has used that MAOP since at least 1975. During the establishment of the initial MAOP documentation in the mid 1970s, in accordance with CFR 192.619(3), San Francisco Division personnel incorrectly identified the highest pressure at which the line operated as 390 psig, which was reflected on the PLSS. Records were later corrected to match the 400 psig operating pressure which was the maximum that this line operated at during the 1965-1970 period."[28]"

Neither the above explanation nor the 2003 hand-written correction to the MAOP log agrees with the history detailed in Appendix 1of this testimony, in particular because both ignore the historical distinction that PG&E had been made between the two sections of the pipeline. The Pipeline Survey Sheets and the other records discussed above identify the MAOP for the section of pipeline between Mile Posts 35.84 and 46.59 (which includes Segment 180) as 390 psi, not 400 psi. However, in 2003, PG&E reset the MAOP for Line 132 between Mile Posts 35.84 and 46.59 and at

[24] Response to DR 30 Q 30 Atch 85 (example).

[25] Response to DR 5 Q 9, Atch 8.

[26] Response to DR 5 Q 9, Atch 8.

[27] Response to DR 7 Q15, which requests copies of all uprating requests submitted to the PUC does not include an uprating request for L-132.

[28] Response to DR 3 Q 20.

some time, either then or later, entered notes on historical documents to record the change. All of the MAOP tables (Drawing 086868) and records PG&E has produced in this proceeding reflect 390 psi MAOP from 1978 to 2003 for the section of Line 132.

Records explaining the downgrading of the MAOP to 390 psi between MP 35.84 and MP 46.59 have not been produced. PG&E should have validated the MAOP before changing it, but there is no record indicating that it did so. Further, PG&E relied on 1968 records to make the 2003 "correction," increasing the MAOP from 390 to 400 psi. Even if PG&E could show that the MAOP of 390 psi reflected in its records was simply a mistake, the fact that the mistake persisted in PG&E's operating records, viewed daily by operating and engineering personnel for 25 years (until 2003), and then continued to persist until 2010 on some PG&E records after the mistake was identified, is in itself a testament to PG&E's poor recordkeeping practices.

In summary, the MAOP records for Line 132 are incomplete. Despite the continued assertion that it had been operating the line at 400 psi, there are several contemporaneous and chronological records documenting 390 psi for the section between Mile Posts 35.84 and 46.59.. PG&E's subsequent, handwritten edits to these records to support the 2003 change to the historical record or to support abandoning the lower MAOP for the section of Line 132 between Mile Posts 35.84 and 46.59 establish why PG&E's poor recordkeeping was an unsafe business practice.

2.3 <u>Deficiencies in Clearance Recordkeeping</u>

PG&E failed to follow its records procedures, called the "clearance process," for planning the September 9, 2010 work at Milpitas Terminal. The clearance process is PG&E's detailed procedure for maintenance projects that can potentially disrupt service.[29] The work procedure provides very specific instructions designed to lead operating and maintenance personnel through a project in a way that will ensure the safety of the worker, the plant and the public. The procedure requires extremely detailed documentation to be recorded and accessed electronically, and also reproduced and filed in hard copy. Clearance communications and required records are to be documented in PG&E's electronic Clearance SharePoint system.[30] For the uninterruptible power supply project that started on September 9, 2010, PG&E did not follow its own clearance procedures.[31]

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[29] P2-314, Utility Work Procedure WP4100-10.

[30] SharePoint is a Microsoft product marketed to businesses to allow people within a company to share information, manage documents from start to finish, and to publish reports. PG&E uses SharePoint to draft, coordinate and finalize policies, standard procedures as well as documenting clearances for work on

The clearance application was initially submitted in the computer system for approval on August 27, 2010. This clearance application, required for Milpitas Terminal maintenance work on September 9, 2010, was substantially incomplete, leaving the maintenance crew and control room operators without the required step-by-step plan for the work they were doing.[32] In response to a data request, PG&E provided a copy of the clearance filed after September 9th to complete the work on the uninterruptible power supply that was left unfinished on September 9th. This later clearance follows PG&E procedures and shows what the original clearance records should have looked like. For comparison, copies of both clearances are provided as Appendices 2 and 3 to this report.[33]

If PG&E personnel had followed the clearance procedure, there would have been a step-by-step plan put in place before the September 9, 2010 work at Milpitas began. Drawings would have been readily available to the maintenance crew doing the work and to Gas Control personnel who were attempting to help once problems arose. PG&E's clearance procedure is an important record system designed to ensure the safety of employees and the public when work is being done to the operating system. PG&E's apparent failure to require strict adherence to this safety procedure is an important record system failure.

2.4 Out-of-date Operating and Maintenance Instructions for Milpitas Terminal

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gas facilities. References to SharePoint were found in other documents. See P2-7, page 9, Section 6.7 and P2-670, p. 3, Sec 3.1.3.

[31] P2-314 and P3-10034, PG&E Utility Work Procedure WP4100-10, Attachment 1 to WP4100-10 is the Control Room Clearance Procedure, which defines the roles and responsibilities, required processes, communication tools and methods, and documentation required for a gas work clearance.

[32] Response to DR 37 Q1, A Clearance is a plan to do work that is submitted within the PG&E system to make sure everyone involved is aware of the work being done on the gas system while it is operating, knows when the work begins and when it is completed. The plan is essential to safe operations. For instance, when an application for a clearance is completed on the SharePoint system, a clearance supervisor must be identified. The partial application for September 9th shows the clearance supervisor as "TBA," or to be assigned. Apparently a clearance supervisor was never assigned. The Clearance Supervisor is responsible for and manages the clearance. Clearance Supervisors must be qualified to perform the clearance procedure and equipment they Report On be knowledgeable of clearance points and have the ability to ensure that equipment is cleared safely The Clearance Supervisor is the first person to Report On and the last person to Report Off for any clearance The Clearance Supervisor is responsible for all clearance logs Clearance Communications Board documentation and tagging.

[33] Response to DR 47 Q 4 Attachment 1 (September 9, 2010) and Response to DR 47 Q 11 Attachment 3 (October 2010).

The Operating and Maintenance Instructions manual at the Milpitas Terminal was out of date on September 9, 2010, possibly by as much as 19 years, which would make it a useless reference when the emergency occurred.

When PG&E schedules work to be performed on its electrical system, especially on a system that powers pipeline instrumentation such as automatic and control valves and the data transmission system, it is essential both to have competent and knowledgeable personnel doing the work, and for those personnel to have all of the relevant maps, drawings, and manuals at hand before beginning the work. All of those records must be up-to-date, so that they accurately reflect the system as it exists on the day of the project. PG&E states that it does not know whether the latest Operating and Maintenance (O&M) Instructions manual was at the Milpitas Terminal on September 9, 2010 and is unable to verify what version of the manual was there.[34] PG&E explains as follows:

> "PG&E confirmed that each of these facilities contains a hard copy version of the Operating and Maintenance Instructions applicable to that station, although not all 11 contained the most recent revision. It is not possible to ascertain whether the version contained at a station as of July/August 2011 was the exact version that existed on September 9, 2010, and in several instances new revisions of Operating and Maintenance Instructions have been issued since that time. PG&E personnel who operate and maintain unmanned major facilities have access to the Company intranet, where the latest version of the relevant policies and procedures exist."[35]

During this investigation, PG&E produced a copy of Operating and Maintenance Instructions for Milpitas Terminal, Revision 6 (2009) and in the I.11-02-019 proceeding, PG&E produced Revision 7 (2011).[36] When asked, PG&E failed to produce a copy of the O&M manual that was at the Milpitas Terminal on September 9, 2010, but it listed a 1991 manual in a Summary Inventory of Milpitas documents.[37] PG&E did not produce a copy of the 1991 manual for review. Failing to provide updated Operating and Maintenance Instructions over the course of many years reflects a deficiency in an important area of documents and records.

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[34] Response to DR1 Q1b Supp 02, p. 19 (note: Milpitas is an unmanned facility.).

[35] Response to DR1 Q1b Supp 02, p. 19.

[36] Rev 6: Response to DR 1 Q1b, Attachment 42 (file mislabeled by PG&E as DR1-Q0(42)) and Rev 7: Response to CPSD 242 Q2, Attachment 1.

[37] Response to DR 1 Q 7, Attachment 2. p. 3.

2.5 Out-of-date Drawing and Diagram of the Milpitas Terminal

On September 9, 2010, PG&E personnel at the Milpitas Terminal may have been working with an outdated map and control room personnel may have been working with an incomplete diagram of the Milpitas terminal.

When trying to control the pressure by manually opening or closing valves, PG&E personnel needed access to current and accurate drawings. If the personnel at the Milpitas Terminal were referring to the piping and instrumentation drawing available at the Milpitas Terminal during that crisis, they may have been using a drawing that was incorrect.[38] In response to a data request, PG&E verified that drawing #383510, which it submitted to the NTSB, had been corrected after September 9, 2010 to accurately reflect the terminal design on that date. Thus, the drawing available to the personnel at Milpitas Terminal on September 9, 2010 did not accurately reflect the then current terminal design. In addition, the diagram for the Milpitas Terminal that was used by San Francisco Control Room operators was inaccurate and incomplete. The diagram has been revised three times since the San Bruno incident.[39] On September 9, 2010 the diagram at the Control Room was apparently missing a bypass line outside of the Milpitas Terminal fence line. This appears to be a significant inaccuracy in the diagram because, during the emergency, PG&E personnel were attempting to control high-pressure gas that they thought might be by-passing the Terminal.[40] [41]

> "On October 27, 2010, existing valves and piping related to the bypass system were added to the SCADA Milpitas Terminal operating diagram to provide Gas System Operators additional visibility of the bypass line configuration outside the Milpitas Terminal fence line. The valves that were added to the diagram were V-0.11, V-0.12, V-0.13, V-30, V-31, V-32, V-57.45, V-300, V-400, V-401, V-500, V-502.12A, V-600 and V-602, along with the associated piping . . ."[42]

Based on the San Francisco Control Room transcripts for September 9, 2010, it seems there was confusion between the person at the Milpitas Terminal and the Control Room Operator

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[38] Response to DR 3 Q 15.

[39] Response to DR 8 Q8.

[40] Transcripts

[41] Response to DR 8 Q 8 (c).

[42] Response to DR 8 Q 8 (c).

about valve numbers at the Milpitas Terminal.[43] At least some of the confusion experienced at the Milpitas Terminal and the Control Room during the emergency appears to have been related to inadequate reference documents.

2.6 No Back-up Software at the Milpitas Terminal

The first indication of a problem at the Milpitas Terminal was described by the PG&E maintenance personnel on site as a loss of controllers. He clarified the situation in a subsequent interview by stating that they lost the programming to 3 controllers. Despite PG&E's policy quoted below to have a back-up of the software onsite, there was no backup at Milpitas on September 9, 2010.

> "The PLC system is located in the computer room in the Control Build. . . . The 3 Ethernet Interface modules in each PLC rack are to provide communication with the Process Automation Controllers (PAC). Only the modules in the PLC, which is in control (Master or Slave), are communicating with the PAC controllers.
>
> The 2 serial Communication Coprocessor modules in each PLC rack are used to provide serial communication interfaces between the PLC and the local HMI and the PLC and SCADA terminal in Gas Control. . . .
>
> The PLC may be accessed via programming terminal in the computer room or any PC with the GE VersaPro software. *Copies of the program are kept on the hard disk of the programming terminal and the back-up copies of the programs must be kept on a floppy diskette at the Terminal. A hard copy is available at the terminal.*"[44] (italics added)

In theory, the maintenance person at the terminal could have reloaded the software from his laptop. However, his software was not compatible with the model number of the three controllers that lost programming.[45] An engineer had to be called in to bring the software on his

[43] Response to DR 8 Q 8 c. ant DR 8 Q 8 Attachment 3.

[44] Response to DR1 Q 1b, Attachment 42, Milpitas Terminal Operations and Maintenance Manual, Rev. 6, p. 77-78, 2009.

[45] SF Control Room Transcript Line 11.03.33 PM - .wav file 6079390000394346 ". . . I'll give you a call once [the engineer] starts reloading the programs in there. . . I don't have the software for the 353s. I got all the stuff for the 352s but these are the 363s." and OM transcript, Sept 16, 2010, p. 29 lines 2-4: "My laptop only has a program for the 352 Moore controllers. These are 353 controllers, so I did not have the programming, the software for them." (Note: It is unclear whether the controllers at Milpitas Terminal are 353 or 363 Moore controllers since both are stated here).

laptop computer.[46] The engineer arrived at the Milpitas Terminal several hours later and restored the system at midnight, long after 5:20 p.m., when controllers system had failed.[47]

When PG&E was asked whether employees regularly keep records on their personal electronic devices, the response was:

> "Many PG&E employees have access to numerous electronic copies of technical or engineering records through their laptops or personal electronic devices. Although most electronic records are stored on the company servers, electronic records may occasionally be stored on employees' laptops or personal electronic devices.[48]

Even though there may be some instances in which software may be safely carried by maintenance personnel and engineers for job convenience, it is clearly an unsafe and poor engineering practice for PG&E's only copy of critical software to be on a laptop stored remotely from the programmed equipment.

2.7 The Supervisory Control and Data Acquisition – Electronic Recordkeeping

The data transmission collection and display system for PG&E's gas transmission system is referred to as Supervisory Control And Data Acquisition (SCADA). The SCADA system provides data to the control rooms. On September 9, 2010, San Francisco Control Room operators were alerted by "Hi-Hi" alarms from instruments at the Milpitas Terminal and along the Peninsula pipelines indicating high pressures. The control room policy is to acknowledge all alarms and then the operator has 10 minutes to analyze the problem and respond to the alarm.[49] On September 9, 2010, after controllers were lost and pressure went out of control at the Milpitas Station, many alarms went unacknowledged and repeated regularly, creating long screens of repeating alarms.[50]

A few minutes after the pipeline in San Bruno ruptured, there was a "Low-Low" alarm that came in from Martin Station at 6:15 PM. This alarm was an indication of the San Bruno

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[46] SF Control Room Transcript Line 9.9.2010- 10.58.38- PM - 607939000394344- 0001: [Name]: "We're waiting for <Unintelligible> [name] the engineer to show up, we're gonna load all the programs back in it because we lost the programs on it."
[47] SF Control Room Transcript Line 11:57:23 PM - .wav file 6079390000394367 ". . . Because those are the ones that weren't controlling those, those few and (name) just now got them working."

[48] Response to DR 1 Q 10.

[49] Response to DR 1 Q 12, Attachment 154, p. 5.

[50] Response to DR 1 Q 14, Attachment 2.

pipe failure. Control room operators failed to acknowledge the alarm and did not recognize the drop in pressure until almost 30 minutes later, when someone from another location called in and asked them to look for the pressure drop on their SCADA screens.[51] In fact, even after they found the pressure drop, they could not identify the location of the pipe failure using SCADA data.[52]

There were no remote control valves installed in Line 132 at the time of the pipe failure because PG&E had decided that they were not warranted. PG&E assumed that the damage from a broken line would occur before the valves closed automatically.[53] In fact, control room operators did not know if there were any valves that could be used to shut off the gas.[54] Because the control room operators failed to detect the pipe failure and were unable to immediately determine its exact location and were unfamiliar with the location of valves, they could not provide useful information to field personnel and managers. Such information might have been helpful in reducing the amount of damage that occurred by shortening the one hour and 35 minutes it took PG&E to shut off the gas.

2.8. Emergency Response Plans Too Difficult to Use

PG&E's Emergency Response Plans were difficult to use and were a source of confusion for the Control Room operators, probably contributing to PG&E's inability to mount a credible response to the incident on the evening of September 9, 2010. PG&E's emergency plan is very complex and was apparently difficult for personnel to implement during the San Bruno emergency.[55] The summary reference pages for personnel to refer to are shown in Figures 1 and 2.

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[51] Response to DR 1 Q 14, Attachment 2 , see highlight at 18:15 PM

[52] Response to DR 30 Q 21 Interviews of PG&E Employees conducted by the NTSB Interview September 16, 2010, Interview of MV, p. 25: ""We knew . . . as we were pulling maps and diagrams and laying them out on the table that it was a line break. But . . . it wasn't confirmed until we got a call from the field engineer."

[53] P3-30154 p. 16 (NSEG 132 2004 Long Term Integrity Management Plan, approved 4/26/2010).

[54] Transcript_Excerpt_Valves_Between_stations

[55] SF Control Room transcript.

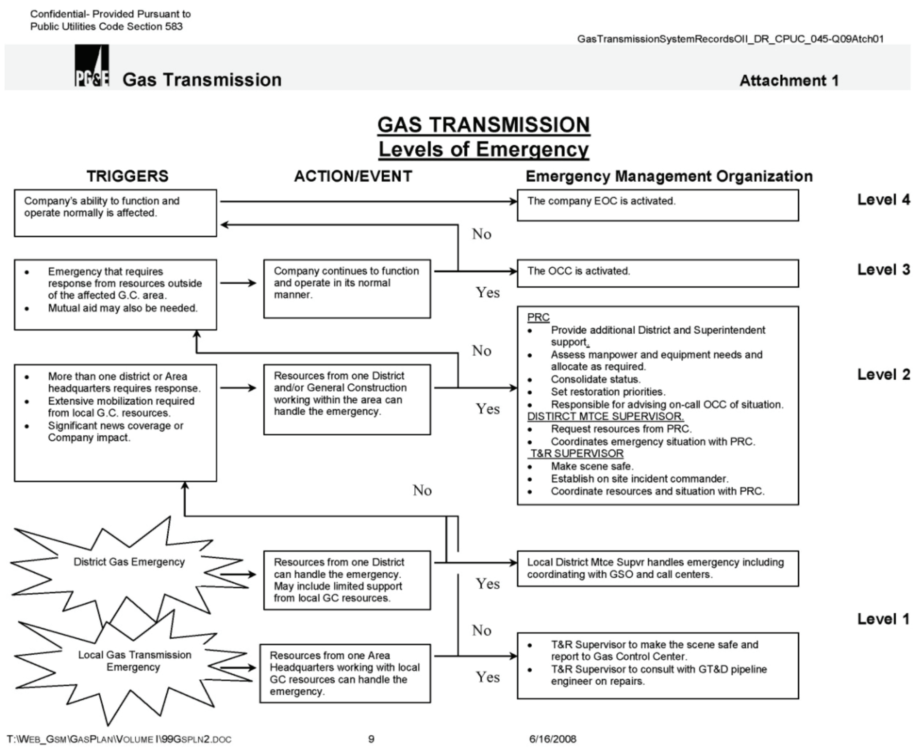

Figure 1

On the transcript of the audio recording made in the San Francisco Control Room during the emergency, it is clear that there was confusion about the emergency response plan.[56] Studying Figure 1, which is supposed to be the short-hand guide to responding to an emergency, confirms that the confusion was warranted. For example, it is not clear who in PG&E was supposed to be in charge of the response to the San Bruno incident, a level 4 emergency.[57]

Emergency response plans are useful only if they are written and implemented in a way that makes the information immediately accessible and easy to understand and to follow in situations when events are overwhelming. The plans must be updated regularly so an employee or contractor will not rely on obsolete information or call invalid phone numbers to reach key personnel. The complexity of PG&E's Emergency Response plan can be seen in the flow chart it

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[56] SF Control Room Transcript: excerpt_ER_Confusion.

[57] The trigger for Level 4, as described on the diagram, is "Company's ability to function and operate normally is affected."

provides to its employees.[58] (Figure 2) Each center referenced is opened by a predefined manager within PG&E.[59] "EOC" is the Corporate Emergency Operations Center. "OOC" is the Operations Coordination Center. "OEC" is the Operations Emergency Center and "PRC" is the Pipeline Restoration Center. Not shown on the diagram, but referenced in the Company-wide Gas Emergency Response Plan is the "CCECC," or Call Center Emergency Coordination Center.[60]

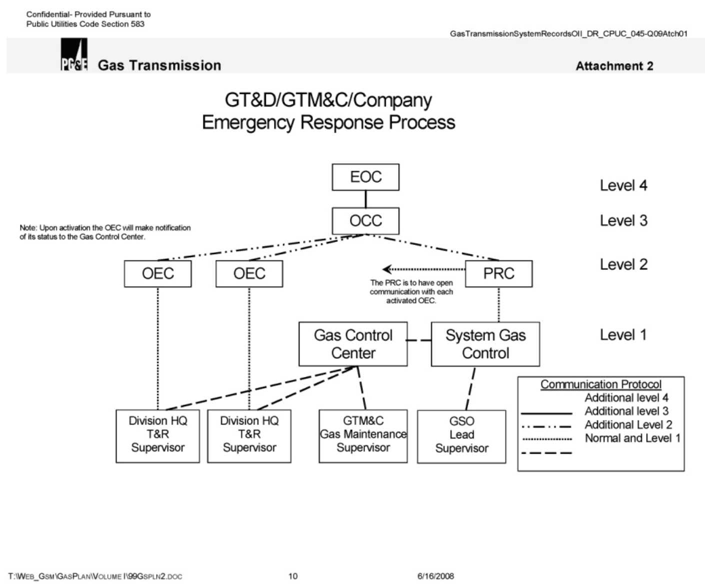

Figure 2

PG&E describes its emergency response guidance as follows:

> "As of September 9, 2010, there were three sources of emergency procedures that PG&E maintained that applied to transmission line incidents, including incidents that occurred at Stations and System Gas Control facilities within PG&E's transmission system. First, PG&E maintained a Company-wide Gas Emergency Plan. This plan is utilized throughout the Company and the gas organization. Second, each of PG&E's 17 divisions maintains a Gas Emergency Plan. The Division Emergency Plans contain substantially the same substantive information. The differences between division

[58] Response to DR 45 Q 9, Attachment 1.

[59] Per the Company-wide Gas Emergency Plan.

[60] Per the Company-wide Gas Emergency Plan, Part 1, p. 35.

> plans primarily relate to emergency contact information, which is unique to each division. Third, gas transmission districts also utilize the GT&D and GTM&C Emergency Plan Manual. It consists of two volumes. Volume One describes the emergency plans of Gas Transmission & Distribution (GT&D) and Gas Transmission Maintenance & Construction (GTM&C) and how they integrate with PG&E's emergency management organization. Volume Two provides guidance to field personnel responding to an emergency. The guidance includes phone contacts for support services, emergency pipe stock inventories, and emergency response check lists.
>
> All of the Emergency Plans and Manuals are accessed by PG&E employees online through the Gas Transmission document library. The online versions of the Plans and Manuals contain a table of contents with hyperlinks to each individual document contained therein."[61]

PG&E's manuals are difficult to follow and some sections appear to be out of date, still referring to the previous organizational structure in which the main control room was in Brentwood and a supervisory function was in San Francisco.[62] The unwieldy length of these documents presents a potential problem for functionality. The company-wide gas emergency plan is 536 pages long. The CGT Emergency Plan is 347 pages and the Peninsula Division Plan is 688 pages.[63] The plans provided were dated 2008. Operating a safe gas transmission system requires emergency plans that can be readily understood and followed in an emergency.

3.0 RECORDKEEPING ISSUES HAVE HISTORICALLY CREATED DEFICIENCIES IN PG&E'S INTEGRITY MANAGEMENT EFFORTS

The purpose of this section is to take a critical look at the implications PG&E's poor recordkeeping practices have for its gas transmission system and its integrity management program risk ranking models. Virtually all of the records required to create accurate and useful risk program models that are discussed below are records that were required to be kept for the life of the facility and, in some instances, for the life of the facility plus 6 years.[64]

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[61] Response to DR 1 Q 8.

[62] Response to DR 47 Q 25: PG&E began using the San Francisco control room as the sole main control room, with Brentwood as the back-up, on April 4, 2010.

[63] Response to DR 1 Q 8, p. 38 (PG&E provided emergency response plans one page at a time): CGT Emergency Plan, 341 pages, Company Wide Gas Emergency Response Plan, 536 pages, and the Peninsula Division Emergency Plan, 688 pages.

[64] Response to DR 9 Q1, PG&E acknowledges this requirement in the revised Table 2A-3. The Table is

The Transmission Integrity Management Program (TIMP) regulations effective in 2004 require operators to take specific steps to manage risk in natural gas pipeline systems. PG&E's current integrity management program has at its core a risk assessment model that it began building in 1984 as part of its Gas Pipeline Replacement Program (GPRP).[65] The scale of PG&E's current model is much larger than the initial 1984 model because PG&E has included more data fields and pipeline segments. However, the underlying concept is the same, i.e., PG&E defines risk as the product of the likelihood of failure times the consequence of that failure (LOF X COF) and the basic structure of the model is the same as it was in 1984.

3.1 Records of Pre-1984 Pipeline Replacement at PG&E

PG&E cannot cite to any specific program prior to the 1980's to inspect its pipelines and plan for orderly replacement. In its June 20, 2011 filing PG&E states: "[i]t is not possible to identify and accurately summarize every pipe replacement job done these many years ago that was or may have been based on a written safety risk assessment."[66] And, PG&E says it sought to reduce risk on its gas transmission system principally through pipeline specific analyses and projects.[67] PG&E points to numerous examples of individual pipeline replacement projects where pipe was replaced for integrity-related reasons, primarily leaks caused by corrosion.[68] Upon review of these records, it is clear that PG&E's approach to pipe replacement was to wait until a pipe had so many leaks that it was no longer feasible to add one more repair. The following examples illustrate PG&E's approach into the 1970's.

- <u>38 Leaks:</u> "The above sections of main were installed bare 38 years ago with a MOP of 500 psi and traversed grazing and dry farming land with a high soil resistivity. As irrigation increased in the area pipe corrosion increased causing 38 leak repairs."[69]

- <u>97 Patches:</u> There are 19 street patches each representing an excavation, for the purpose of repairing leaks. . . that have been made over a period of six years, most of them in 1959 and 1960. In each hole, the pipe was found to be badly pitted and corroded (wall thickness being reduced up to 40% of its original

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provided in this report as Appendix 4.

[65] P3-20024, p. 13.

[66] PG&E Report, June 20, 2011, Page 6C-3 lines 16-26.

[67] Response to DR 1 Q 16, Supp 1. p. 3.

[68] PG&E Report, June 20, 2011, Page 6C-3 lines 16-26.

[69] P3-27424, Proposal to replace two sections of 26" StanPac Line No. 2, 1969.

thickness). Areas as large as 14" in diameter were found where pipe thickness was greatly reduced. A total of 97 patches were welded onto the pipe in the 19 excavations. A number of the patches cover actual leaks while others cover deep pits and corroded areas. Innumerable spots were found where the wrapping was separated from the pipe and formed pockets which impounded water. The longitudinal seam is pitted along each side of the weld making it especially susceptible to leaks. One stretch of seam had to be repaired with a 5' long half sole. The seam was in such bad condition that real concern was felt about the possibility of its splitting open while the crew was working on it."[70]

- 23 Leaks: "The existing line is bare pipe and has had an increasing leakage history. It has had a total of 23 leaks. Fifteen leaks have occurred since 1960, five of which occurred in 1970."[71]

- Still Leaking: "In answer to complaints of gas odor's the main was bar tested [a bar of wet soap is rubbed over the pipe to spot bubbling where gas is leaking]. The main was exposed at 7 locations and 3 temporary clamps, 2 welding patches and 2 half soles installed. Visual inspection of approx. 30 feet of this single wrapped main revealed heavy pitting. . . . A recent bar test, at 50 ft. intervals reveals leakage still persists over the entire area to be replaced. It is no longer practical to maintain this 46 year old main . . . "[72]

- 1 Leak every 3.6 feet: "The City of Oakland had planned to resurface Livingston Street . . . [t]he repaving is by the heater-planer remix process which cannot be used until the gas indications at the surface are eliminated. Line 105 was recently bar tested and (35) indications were recorded on (94) locations tested. . . . Past repairs from 1948 to 1969 indicate (125) welded patches, (576) spot, and (10) circular bands. Twenty-nine percent of the proposed replacement length has had some type of welded repair, averaging (1) every 3.6 feet."[73]

These examples are provided to show that PG&E was primarily reactive to leaky lines, not proactive in planning to replace lines before they posed a safety risk. These examples also demonstrate that PG&E has records of early pipeline leaks and failures and that PG&E was aware that there could be many leaks on some sections of lines.

3.2 Forward Planning For Pipeline Replacement – Records Issues

In 1984, a forward-looking, 30 year plan, called the Gas Pipeline Replacement Plan (GPRP), was proposed within PG&E:

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[70] P3-27430 Proposal to replace part of 20" pipe, Line 101, 1960.

[71] P3-27432 Proposal to replace 26" pipe, Stanpac Line No. 2, 1972.

[72] P3-27435 Proposal to replace 8" main, San Rafael, 1970.

[73] P3-27438 Proposal to replace 20" line, Oakland, 1971.

> "The steel transmission lines proposed for replacement are 38 to 55 years old and were originally installed in open spaces, often in narrow rights-of-way in areas wh1ch have since been highly developed. Many of these pipelines are now in confined areas with reduced ground cover. They need to be replaced with modern pipe to enable PGandE to continue to provide safe and reliable' service. In addition, the three pipelines supplying San Francisco from Milpitas were built between 1929 and 1947 also. They will be replaced with pipelines capable of operating at higher pressures, which will provide sufficient pipeline storage to allow abandonment of the remaining aboveground low-pressure gas holder in San Francisco."[74]

In parallel to the proposed GPRP to replace whole pipelines, PG&E contracted with Bechtel in 1983 to use risk analysis to assist PG&E in identifying pipe that should be replaced.[75] By 1984, Bechtel developed a replacement priority analysis and database to rank the order in which segments of gas transmission lines and distribution mains should be considered for replacement under the program.[76] The concept proposed by Bechtel was to use probability analysis to predict the segments that posed the highest risk.[77] Theoretically, the higher the risk number calculated for a pipe segment, the more likely it is to fail and cause significant injury to people and property. Those segments with the highest risk numbers rise to the top of the list for repair or replacement. Bechtel and PG&E continued to refine the model over the next 20 years. This model was integrated into PG&E's GPRP program and was the precursor to the current PG&E Integrity Management Risk Assessment model.

In its 1990 Annual Progress Report on GPRP PG&E stated that by replacing higher priority pipe first, emphasis is focused on maintaining a safe operating system in the most cost-effective manner.[78] What PG&E did *not* say in its report was that it did not have adequate historical data about its pipeline system to populate the required data fields in a risk assessment model so it would produce accurate and useful results.

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[74] Response to DR 44 Q 1(a), Attachment 30, p. 3.

[75] Response to DR 44 Q 1 (a) Attachment 29.

[76] Bechtel Report, 1984.

[77] Bechtel Report, 1984.

[78] P3-20024, 1990 Annual Progress Report on PG&Es GPRP, Work was funded in the 1987 GRC, (D.86-12-095).

In 1985, when the initial risk assessment model was ready to be populated with real data, PG&E issued a memo that included a long list of required data and requested assistance.[79]

> "We have now received the data base computer printouts for all Divisions. A copy of this data base for your Division is enclosed. You will note that there are still some areas with missing data. These areas are marked in yellow on the enclosed computer printout. Before we run the risk analysis, we would like to complete the data base as much as possible. Therefore, we ask if your staff would provide any missing information based on the knowledge of Division personnel or retired employees with whom you have maintained contact."[80]

As discussed in section 4.0 of this testimony, PG&E has not been able to find much of this historical data.

Despite the lack of data, PG&E and Bechtel continued to develop the risk assessment model. The discussion below highlights how the relative importance of data changed over time, perhaps due to the lack of certain types of data. And, in some instances, assumptions were made to overcome the lack of actual data. Bechtel assigned the following weighting to variables in its 1984 Risk Analysis model:

- Pipe segment Age: 40%
- leak history: 15%
- weld types 10%
- pressure test type 10%
- coating type 4%
- pipe quality and future performance (anticipated future problems in the event of operating changes) 1%[81]

Pipe Age: The Bechtel model used the date of installation to calculate the age of the pipe. For this variable, an inaccuracy arises in some instances, but cannot be specifically identified, because the installed locations of re-used pipe within PG&E's gas transmission system are unknown. Thus, installation date may not accurately reflect the actual age of the pipe.

[79] Response to DR 44 Q 1(a) Attachment 33.

[80] Response to DR 44 Q 1(a) Attachment 33.

[81] 1984 Bechtel Report, p. 9.

Leak History: Bechtel reported that PG&E's engineers expressed little confidence in the accuracy of leak data, believing the leak history was under-recorded. Bechtel states that its experience is that the number of leaks experienced by any given transmission line segment rarely exceeds two and uses this assumption in the model.[82] However, PG&E's job file records show many segments with many more than two leaks.[83] So, for assessing PG&E's pipelines, Bechtel's assumptions about low numbers of leaks in PG&E's pipes proved to be incorrect. (Yet, the same assumption exists in its TIMP model today.) In 1994 PG&E begins stating in its reports that it began keeping leak records in 1971.[84] PG&E collected leak data on A-Forms, also known as Form 62-4637, much earlier than 1971, but failed to keep it in an accessible manner.[85]

Weld Type: Bechtel included only girth welds in this category. The assignment of points implies gas welds are five times more likely to fail than arc welds: Oxy-Acetylene Gas Welds (10 points) and Electric Arc Welds (2 points). Thus, there is an assumption that PG&E knows the history of the installation of the pipeline segments.

Pressure Test Type: Three types of pressure tests are considered: leak test, gas test and hydro test. The logic is that a poorly executed weld is more likely to go unnoticed if a leak test was performed under pressures well below operating pressures (leak tests) than if a gas or hydro test had been performed. PG&E is in the process of searching its records in a multi-year effort to produce traceable and verifiable records to support the maximum allowable operating pressures it has assigned to its transmission lines. Its search immediately revealed incomplete pressure test records. In addition, some GIS records PG&E has located cannot be confirmed through supporting documentation and therefore are unreliable. For instance, the GIS entry for a gas test for Segment 180 is "Gas" in 1961, but PG&E has not located any supporting documentation for that entry.[86]

Coating Type: The type of coating on a pipe is directly related to protection against corrosion. According to Bechtel, "[t]he problem encountered in using this data variable . . . stems

[82] 1984 Bechtel Report p. 11.

[83] See list examples listed above in this report. Also based on the authors review of thousands of PG&E's documents in the ECTS database.

[84] P3-20038 p. 18.

[85] P3-10005(b), p. 118 and also from author's review of PG&E records in the course of preparing this testimony.

[86] Response to DR 45 Q 8.

from the lack of confidence in the information pertaining to the coating type (58% confidence in accuracy) and coating condition (46% confidence in accuracy)."[87] The condition of coatings is reported on PG&E's A-Form each time a pipe is uncovered for a construction project, testing, repair, or inspection. A-Forms are not well organized, are incomplete and are difficult to read. As discussed earlier, PG&E lacks confidence in this data and its concern is justified.

Pipe quality and future performance: The remaining 1% was given to pipe quality and future performance, also stated as "anticipated future problems in the event of operating changes" which were apparently considered unimportant. Bechtel assigned inconsequential values to pipe type and longitudinal seam efficiencies on the basis that "PG&E's lines operate at pressures that conform to G.O. 112 standards, therefore, risk of failure related to these parameters is low." In other words, Bechtel assumed PG&E knew the nature and quality of pipe and pipe welds throughout its system and that it had always operated pipelines at the appropriate pressures based on this knowledge. That assumption cannot be validated because PG&E does not keep pressure operating data for the life of its facilities.

While Bechtel's early work to develop the GPRP prioritization model was underway, PG&E replaced Line 101 and planned to replace all of Lines 109 and 132.

> "In 1985 Pacific Gas and Electric Company implemented the Gas Pipeline Replacement Program (GPRP) to replace aging gas pipe throughout the PG&E system. As part of this program, plans were formulated to replace the three natural gas pipelines supplying San Francisco from the gas terminal in Milpitas. These lines are 109, 132 and 101. The program called for replacing the gas lines with higher quality pipe and for employing more advanced welding techniques. The new pipelines would have lower leak frequencies and higher operating pressures. The higher pressures would provide sufficient pipeline storage to allow abandonment of the above-ground, low-pressure gas holder in San Francisco.
>
> The three pipelines, Lines 101, 109, and 132, were built between 1929 and 1947. Line 101 was replaced in 1985-1990 in order to have one of the three pipelines fully replaced to meet current standards. Line 109 and 132, [are] scheduled for start of replacement in 1992 and 1999 respectively . . . "[88]

[87] 1984 Bechtel Report, p. 13.

[88] SB_HC_3972241 Gas Lines 132 and 109 Replacement Study, March 1991.

But, Lines 109 and 132 were never fully replaced as planned. Instead, these lines became subject to priority assessment and presumably to the output of the risk assessment model – a model lacking the data necessary to accurately identify the pipe segments that presented the highest risk.

Bechtel's 1995 Report, drafted for PG&E, titled Review of the Transmission Priority Analysis (1994 Revision) for the Gas Pipeline Replacement & Rehabilitation Program, refers to the risk assessment model as the "priority analysis and data base."[89] The model is a later version of the initial risk assessment model proposed in 1984. The priority analysis included oxyacetylene girth welds, unshielded arc welds, bell and spigot joint types, narrow angle butt welds and bell-bell, chill joint types. It specifically excluded all pipeline segments with incomplete or unknown data and all pipeline segments installed after 1940, based on the theory that later welds were made "utilizing modern arc welding techniques and joint configurations that represent a relative low risk of failure and are not currently subject to replacement.[90] Given PG&E's lack of weld records for its transmission lines, it is not clear what progress may have been achieved by this addition of higher risk welds.[91]

3.3 The 2004 Transmission Integrity Management Program - Records Issues

PG&E is required to have a transmission integrity management program to track and assess the integrity of its pipelines.[92] The Transmission Integrity Management Program (TIMP) requirements are relatively new, having been incorporated into Federal regulations in 2004. But the underlying PG&E engineering responsibility to safely manage the integrity of its high pressure pipelines is not new. PG&E has had this responsibility since it first started transporting gas as a public utility, and perhaps before.[93] PG&E describes TIMP:

> "PG&E implemented TIMP through its existing risk management program. However, where its risk management program applies to all of PG&E's gas pipeline segments operating at a pressure greater than 60 psi, TIMP applies to a subset of those segments

[89] P3-20038, Bechtel Report 1994 Revision, May 1995.

[90] P3-20038, Bechtel Report 1994 Revision, May 1995.

[91] Further discussions regarding the lack of types of records are in Section 4.0 of this report.

[92] 49 CFR Part 192, Subpart O: Subpart O requires all pipeline operators to implement a Transmission Integrity Management Program (TIMP) to assess and manage the integrity of all gas transmission pipelines in High Consequence Areas (HCAs).

[93] GO 112 and CFR 192 regulations, and Section 451 of the California Public Utilities Code.

> meeting the definition of a "transmission line" in 49 CFR Section 192.3. Further, TIMP requires integrity assessments for those segments operating within High Consequence Areas (CHAs), roughly 20 percent of PG&E's existing transmission pipeline segments (or approximately 1,020 miles).[94]

PG&E explained in its report how it continued to develop risk management models "to supplement and improve operational processes related to managing system risks."[95] It says it initiated a Gas Transmission Risk Management Program in 1998.[96] The PG&E model should have proved useful to PG&E in complying with 2004 Federal regulations. PG&E states:

> "In brief summary, prior to 1985, PG&E sought to reduce risk on its gas transmission system principally through pipeline-specific analyses and projects. Beginning in 1985, PG&E consolidated many of these activities into the Gas Pipeline Replacement Program (GPRP), a programmatic initiative that was continually refined. Since the late 1990s, PG&E has performed risk assessments on its gas transmission pipelines through a Risk Management Program that anticipated Integrity Management regulations in 49 C.F.R. Part 192 Subpart O, which were introduced in 2003. Under the Risk Management program, PG&E utilizes its integrity management risk assessment model to evaluate potential risks on transmission pipeline segments and to analyze those segments to determine the most effective actions to reduce that risk."[97]

Since 2004, PG&E has been developing a large integrity management risk assessment model based on the original Bechtel model. It runs on a Microsoft Excel spreadsheet (in 2009 the size of the spreadsheet was 19,963 rows (pipe segments) by 342 columns (input data, information and calculations).[98] The model is supported by many guidance documents, ongoing field data collection mostly related to external corrosion, and constant system modeling and report writing activities.[99] Under its risk management program, PG&E utilizes its integrity management risk assessment model derived from the Bechtel model to evaluate potential risks

[94] Pursuant to Method 2 of the HCA designation criteria set forth in 49 CFR section 192.903; PG&E Report filed June 20, 2011, p. 6C-11.

[95] PG&E Report filed June 20, 2011, p. 6C-9.

[96] PG&E Report filed June 20, 2011, p. 6C-9.

[97] Response to DR 1 Q 16 Supp 1.

[98] P3-20060_1_thru_3(N)_CONFIDENTIAL.

[99] Response to DR 3 Q 7, a list of TIMP related documents.

on transmission pipeline segments and to analyze those segments to determine the most effective actions to reduce that risk.[100] One output from the integrity management risk assessment model is the annual "Top 100" pipeline segment list that, according to PG&E, presents the segments with the highest risk of failure in the "discrete categories: the potential for external corrosion, third-party damage, the physical design and characteristics of the segment, the potential for ground movement, and the overall risk of the segment."[101] However, PG&E recently said that it does not currently maintain a top 100 list. Instead, PG&E provided a combined list of the segments included on the 2007, 2008, and 2009 top 100 lists for long-range evaluation and planning to the CPUC on February 11, 2011, and updated the list on March 9, 2011.[102]

PG&E stated that it uses the results of the risk model to prioritize and justify projects by providing the risk score before a project is initiated and providing a predicted score for after the work is completed, thereby showing the reduction in risk of failure as a result of performing the repair or replacement project.[103] However, the effectiveness of this risk model is directly related to the quality of the data used in the model and the quality of the data is suspect (in many instances the data is assumed or missing). Therefore, using this model to prioritize projects seems risky in itself because high risk projects may be overlooked.

While the number of documents produced from the integrity management program is impressive, a review of the actual spreadsheet model reveals an unimpressive model that simply adds up data entries and assigned points based on some simple calculations to arrive at a total risk number for each segment. The combined lack of data, assumed, unknown values, and questionable quality of the data entered into the model spreadsheet, suggests the model is of only minimal practical use and is more likely entirely useless in calculating total risk. PG&E's risk modeling efforts have always suffered from a deficiency in basic historical data and its current risk management model suffers from the same problem. As a result, the rankings generated from the model cannot be an accurate representation of the real likelihood of failure of segments. The

[100] Response to DR 1 Q 16, Supp01, Note: this statement assumes the risk assessment model contains complete and accurate data, which is not the case to date.

[101] PG&E's Report, June 20, 2011 p. 6C-13 and P3-20052.

[102] Response to DR 57 Q 6: Per PG&E, a copy of that list is available at http://www.cpuc.ca.gov/NR/rdonlyres/4EF3C8C7-6895-4F3D-903B-8FC07B4B277B/0/Mar9PGETop100ErratatoCPUC.pdf

[103] PG&E Report filed June 20, 2011, p. 6C-15.

pipes most likely to fail are not being identified accurately due to a lack of relevant, accurate, complete and accessible data. Thus, PG&E's current integrity management program itself presents a safety risk to PG&E's field and station employees and the public.

3.4 PG&E's Claim That Transmission Integrity Management Program Regulations Require Special Data Is Baseless

PG&E has been required by industry standards and by regulations to maintain records about its facilities for the life of the facility.[104] This records retention requirement is fundamental to industry because the transportation of gas is a dangerous activity. Failures in high pressure pipelines, especially those containing hazardous and/or flammable materials such as natural gas, can result in destruction to life and property.

However, as shown in the quote below, PG&E claims that TIMP imposes special data management requirements well beyond the recordkeeping program PG&E already had in place. When PG&E was asked why it had stated that the federal TIMP rules created new demands for accessing, reviewing and integrating historical pipeline information and records in ways that its existing recordkeeping systems and practices were neither designed nor intended to address, PG&E responded:

> "TIMP rules have a different focus from maintaining records to demonstrate compliance, operate the system, or perform discrete engineering or maintenance activities safely. TIMP rules focus on a more system-wide approach to evaluating pipeline integrity. As PG&E previously explained in its June 20, 2011 response, the data gathering, integration and review requirements of TIMP have presented data management challenges for PG&E in particular, and the gas pipeline industry as a whole.
>
> The kinds of records that PG&E has attempted to gather, evaluate and integrate include, but are not limited to: information regarding pipe characteristics such as wall thickness, coating material and coating condition, pipe toughness, pipe strength, and other data. . . "[105]

While this may be PG&E's position, had PG&E kept its pipeline history files up to date, complete, and accurate, as required by its own internal policies in place after 1968,[106] PG&E would have had at hand the records it needed to accomplish good integrity management, whether before or after TIMP.

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[104] See Appendix 8, Tables of Regulatory Requirements.

[105] Response to DR 4 Q 7-8.

[106] P2-400, p. 92.

The data requirements for TIMP are not new. Many of the data requirements of TIMP are part of keeping historical records of transmission pipelines which are in original sections of Part 192 from 1970 and previous California requirements in GO 112. They are the same data requirements built into PG&E's risk assessment model in 1984. Furthermore, TIMP calls for the same data that any public utility seeking to "promote safety" under section 451 of the Public Utilities Code would need to keep and organize for prompt and effective access. Thus, even though PG&E claims TIMP has imposed substantial new challenges, it is PG&E's inadequate record maintenance that makes implementation of integrity management challenging.

3.5 PG&E Changes Emphasis of Data in TIMP Model

Possibly as a result of the lack of certain historical records, PG&E changed the weighting of data from the original Bechtel Model (see Section 3.2 above) to the following in the current TIMP model:

- Third Party: 45% (damage from hitting the pipe when digging)
- External Corrosion: 25%
- Ground Movement: 20%
- Design / Materials: 10 % (the sum of the following: pipe seam design 3, girth weld 1.5, material flaws 2, pipe age, 1, MOP v. pipe strength 2, leak history 0.5, and test pressure v. pipe strength 2) [107]

4.0 MISSING AND INCOMPLETE RECORDS NEEDED FOR INTEGRITY MANAGEMENT

This section of this report identifies in more detail the missing record information that PG&E would need to make its integrity management risk assessment model useful in mitigating the risk of pipe failure in its transmission system.[108]

As discussed above, the importance of keeping and maintaining accurate, complete, and accessible records related to facility design, construction, operations and maintenance cannot be overstated. Generally, good engineering practice and State and Federal regulations require retaining facility-related records for the life of the facility.[109] Facility records are important to engineers for multiple reasons, including the following:

[107] P2-150 and P2-157

[108] This section applies to all of the transmission pipelines PG&E has in service.

[109] P2-225(b) Records Retention, pp. 38-49.

- First, the metal in old pipe may suffer from fatigue over time and, at some point, may become incapable of providing the service originally desired;
- Second, operational requirements may change over time, creating stresses the facility was not originally designed to withstand;
- Third, subsequent upgrades to one part of the facility must work within the design of the existing facility (or other pipeline components will require upgrades); and,
- Lastly, all of these records are required to successfully manage the integrity of an aging pipeline system. In all instances, the engineer must know the specifications and operational history of the existing facility over its entire life, in order to properly manage it and minimize the risk of failure.

PG&E's own 2010 guidelines for integrity management, mirroring 49 CFR 192.917(e)(3) requirements, illustrate the importance of maintaining both facility and operational records:

> "In addition, where threats of a manufacturing or construction defect, including seam defects, in a covered segment are identified and any one of the following conditions occur, the segment shall be considered a high risk segment in the baseline assessment plan or in any subsequent assessment.
>
> (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;
>
> (ii) MOP increases; or
>
> (iii) The stresses leading to cyclic fatigue increase."[110]

Accurate, complete, and useable pipeline records constitute a utility's best and, often, its only means to understand its pipes and other components buried in the ground and out of sight, and to maximize their safety.

Specifically, the categories in which PG&E is missing critical data from its records systems are: 1) pipeline history files, 2) job files (including pipe mill reports and any QA/QC testing), 3) pipeline design and pressure test records, 4) weld maps and inspection reports, 5) operational history records, 6) leak records, and 7) salvaged and reused pipe records. Without these records, PG&E cannot have a feasible or useful integrity management program.

4.1 Pipeline History Records

[110] P2-158, p. 34, Section 4.3, from 49 CFR Sec 192.917 (e)(3), see RH-77.

PG&E has not maintained important historical records that included design, construction, leak, repair and operational data, among other things. As a result, PG&E lacks critical information required to make its integrity management risk assessment models useful in managing risk as they are intended. In an illustration of the effect of decades of failed record maintenance, PG&E's Senior Project Engineer succinctly stated the problems posed for him by inadequate records. The following passage is quoted from a May 13, 2010 memo to file:

> "In RMP-13 "Procedure For Stress Corrosion Cracking Direct Assessment . . . there are certain data elements listed as required for which the information is not available in the records. This includes elements such as operating stress levels, hydrostatic test history, pipe manufacturer, and year installed. These requirements will be revised [from "required"] to the "desired" category in the next procedure revision to reflect the reality of available records not containing the needed information. The operating stress levels are not available because of missing pipe data. With every available excavation that is conducted on these or related segments, we will acquire the pipe information and update our records."[111] [112]

Because PG&E is missing historical data about its pipelines, it must use erroneous and incomplete (assumed and/or of unknown quality) information in its integrity management risk assessment models. This lack of information has resulted in the assignment of incorrect risk priorities (for replacement and assessments) to pipeline segments.

4.1.1 Early Pipeline Records, Many Missing or Lacking Detail

As early as 1967, PG&E claimed it had historical records. In 1967, PG&E compiled a document called "Pipeline Surveillance Procedures and Records, and History File Description" and submitted it to the PUC to comply with a request for copies of standard procedures, as

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[111] P3-27238, Compliance Documentation, 2006 SCCDA Program, p. 22.

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[112] P2-164 "RMP" is the designation given to a risk management procedure. This RMP-13 sets out requirements for the data required by the integrity management risk assessment model to determine risks associated with Stress Corrosion Cracking. In each such procedure there is a standard sheet that lists the various types of data they must collect. Each data element in the risk assessment model is identified as "required" (R), desired"(D), "considered" (C), or "not required" (NR). Theoretically, the model will not run without all of the required data elements entered. The problem can be avoided where required data cannot be found by simply changing the category for that data element from R to one of the other categories. The same data element sheet is used for various purposes associated with the TIMP model to identify the types of data (elements) and to assign the appropriate R, D, C or NR codes to each element. Each sheet is unique to the part o the program (and model) it is intended to support.

required under Chapter V of General Order 112-B.[113] This document contains the earliest PG&E statement identified in this investigation of PG&E's method of keeping pipeline data. It states:

> "Although some data, such as original and test information and special surveys, are filed by main number, the majority of the data developed to record replacement, reconditioning, leakage, and other operating and maintenance activities are filed in numerical sequence, depending upon the type record and the system used in a particular division. Reference to these numbers, quite often with a brief description, is posted to the pipeline plat sheets. This serves as an index to the history files and presents a graphical representation of the maintenance and repair activity. Some divisions also post to a full size or reduced size wall map for a better overall review."[114]

Many of PG&E's older drawings (called Plat Sheets) are stored in the Walnut Creek engineering library and are available electronically through the Engineering Library Services (ELS) system. Some of the drawings that pre-date the mid-1970s contain the detailed information noted in the quote above. Unfortunately, many early drawings are missing and many others, including older drawings associated with projects performed in-house by PG&E (instead of a contractor), lack the detail described above and supporting documentation cannot be found. For instance, the Job File for the 1956 Crestmoor project that installed Line 132, Segment 180, has only two drawings. The drawings contain no details about the construction of the pipeline segment and there is no supporting documentation in the project file regarding the pipe used, the QA/QC performed or any other test or inspection information.

4.1.2 **Pipeline History Files Discontinued, Now Missing**

By December 1969, PG&E formalized its pipeline history policy into Standard Practice 463.7, "Pipeline History File, Establishing and Maintaining." The purpose stated was "to provide a current and uniform history record for pipelines (and mains) that have a Maximum Allowable Operating Pressure (MAOP) resulting in a hoop stress equal to or greater than 20% of the Specified Minimum Yield Strength (SMYS)."[115] This Pipeline History file was to include various reports relative to inspection and maintenance, as required by applicable portions of PG&E's Standard Practices, including:

a. Pipeline or main number

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[113] P3-10005(b) p. 3 (letter) and p. 12 (report).

[114] P3-10005(b) p. 244.

[115] P2-400 Pipeline Survey manual, 1986, p. 90.

b. Dates of original installation and subsequent changes requiring work orders

c. Design and construction data covering the original installation and subsequent revisions requiring work orders or GM estimates

d. MAOP of each section

e. Type of protective coating originally or subsequently installed and the existing condition of the coating

f. Cathodic protection installations showing locations, ratings, and installation dates.

g. Record of pipeline or main inspections

h. Record of pipeline or main leakage surveys and repairs

i. Record of location class surveys

j. Record of pipeline or main sections where hoop stress corresponding to MAOP exceeds that permitted for new pipelines or mains in the particular class location.

k. Initial or most recent strength test data.

l. Special studies and surveys made as a result of unusual operating or maintenance conditions, such as earthquakes, slides, floods, failures, leakage, internal or external corrosion or substantial changes in cathodic protection requirements.

m. Annual summary of existing condition of pipelines and mains based upon available records as per Exhibit A.[116]

n. Specifications for materials and equipment, installation, testing, and fabrication shall be included or cross-referenced to this file.[117]

These Standard Practice 463.7 Pipeline History Files, if implemented and maintained as described above, would have provided an ongoing record of each pipeline and should have been retained for the life of the facility.[118] Accurate and complete pipeline files would have provided a means to accurately prioritize pipe replacement using the risk assessment model approach. This 1969 Standard Practice was included in PG&E's 1986 Pipeline Survey Manual, which also

[116] P2-400, Pipeline Survey Manual, p. 92 refers to Exhibit A - Form 75-352. "Annual Report for Pipeline and Mains Operating at or Over 20% SMYS", See also P2-2 p. 37 (Form 75-352 is S.P. 463-7. Record retention is for Life of Facility).

[117] P2-400 p. 91.

[118] P2-400 p. 92, SP 463.7 Supplement, Page 2, "Records," Sec 12: "The complete and main history files shall be maintained up to date by the Division or department for the life of the operating facility."

included detailed instructions for creating records titled "Pipeline Survey Sheets." A PG&E Vice-President directed and authorized that the records be created and maintained.[119]

During this investigation, when asked to produce Pipeline History Files, PG&E responded, that it "believes" SP 463.7 became inoperative in the early 1990's when PG&E initiated the transition to its electronic Geographic information System (GIS).[120] PG&E also stated that it "no longer maintains Pipeline History Files."[121] Moreover, PG&E did not produce any pipeline history files in response to the data request. PG&E has not explained when or how it stored or disposed of these files. However, a record produced by PG&E dated October 9, 1987, shows that PG&E discontinued the policy of maintaining the pipeline files via a memo sent out from the PG&E Organization Planning and Development to PG&E Department Heads. The memo stated "[w]e have been asked to cancel the following Standard Practices . . . Please remove and discard these SP's from your SP books."[122] The list from the memo is shown in Figure 3. The fifth item in the list, Standard Practice 463.7, discontinued a recordkeeping system that had been in place for at least two decades as though it were a routine matter.

025.25-1	Air Navagation, Obstructions to
250-1	Accident Investigation-Photographs and Drawings
254-4	Damage to Customer's Electrical Equipment
441.5-4	Protection--Oper. Protective Relaying & Assoc. Auto Cntl Eq.
463-7	Pipeline History File, Establishing, and Maintaining
471.1-1	Telephone Instrument Card
522.1-2	Pipe, Bare & Coated, the Care and Handling of
550.2-4	Driver's Licenses, Medical Examinations
570-9	Use, Care, and Exchange of Padmounted Transformer Barriers
712-7	Outside Employment
726-5	Measuring in Proximity to Energized Lines or Apparatus
726-11	Accident Prevention Recognition Awards Program
726.1-1	Company Drivers' Permits
733-1	Service Emblems
750-1	Self-Contained Underwater Breathing Apparatus (SCUBA)
751.3-1	Loaning the Services of Company Employees or Company Prpty.
761.8-3	Retirement Recognition Luncheons

[119] P2-400 p. 91, SP 463.7 Page 1.

[120] PG&E Response to DR7 Q9.

[121] PG&E Response to DR7 Q9.

[122] Response to DR 34 Q 1 Atch 5.

Figure 3[123]

4.2 Job Files Incomplete and Disorganized

After discontinuing and apparently discarding is pipeline history files, PG&E's Job Files became PG&E's primary source of data for its integrity management risk assessment models. From at least 1929, PG&E retained engineering documents related to completed projects in Job Files. Each Job File was labeled with the Job File number assigned to the project by the accounting department.[124] According to PG&E, it keeps a master Job File, which includes a specific set of original documents.[125] The master Job File is the file of record.[126] There are also individual job files maintained by various persons working on a project. According to PG&E, documents in an individual job file generally do not become a part of the master Job File.[127]

Despite being titled master Job Files, many PG&E Job Files are missing.[128] Those that do exist are frequently missing leak and pressure test results, x-ray results for field welds, field inspection logs and notes, and specific information about how the pipe itself was constructed. PG&E's files sometimes lack any clear and unambiguous record or notation regarding the source of piping – i.e. whether it was purchased new or originated from a salvaged and reconditioned pipe from another PG&E pipeline. Obviously, if the pipe had been previously used, its history and pipe characteristics would be critically important to assessing the remaining life of the pipe when it is placed back into service. This concept seems to elude PG&E since it specifically excludes previous pipe history from its risk assessment models.[129]

PG&E has a history of destroying or discarding important records. Despite requirements that date back to 1912 (by California regulations) and 1970 (by Federal regulations) to retain facility related records permanently, PG&E readily admits that records may have been discarded or misplaced as early as 1980 and continuing through 1996. In Table 2A-2 of PG&E's June 20, 2011 filing, PG&E states that "Moves require recordkeeping decisions to be made, based on

[123] List from response to DR 34 Q 1 Attachment 5.

[124] Based on review of PG&E's Job Files that include project and accounting records.

[125] Response to DR 51 Q 4

[126] Response to DR 17 Q 5.

[127] Response to DR 17 Q 5.

[128] See Testimony of Paul Duller, Records Expert for CPSD in this proceeding.

[129] P2-158.

current operational needs, engineering judgment and recordkeeping requirements, [1980-1996]" and "some pipeline records were misplaced or discarded around this time frame [1995-1996]." When questioned about the missing records, PG&E explained:

> "Based on available information, we have concluded that some records went missing or were destroyed during this time frame. However, we have been unable to conclusively determine which records are missing or the time period in which they were lost. Moreover, it is also possible that during these (sic) time frame or other time frames, additional records, including so called "life of the pipeline" records may have been misplaced or discarded."[130]

Missing Job Files, which are the primary source of information about the construction of PG&E's pipelines, means missing data that is required for a successful risk assessment of its pipelines.

4.3 Many Design and Pressure Test Records Missing

PG&E is missing many pipeline design & pressure records, which are vital to the successful implementation of the company's integrity management risk assessment model. Despite specific PG&E policies which include instructions to retain traceable and verifiable design and test records, PG&E has failed to do so. PG&E states "Some records to validate the Maximum Allowable Operating Pressure (MAOP) are still under investigation and may be missing."[131]

PG&E formally incorporated design and test requirements for piping systems into its Standard Practices at least as early as 1965.[132] Before then, PG&E followed ASME and API guidelines.[133] According to PG&E, the purpose of its 1965 Standard Practice 1604, "Design and Test Requirements for Gas Pipe Systems," was to establish a uniform company policy for designing and testing gas piping systems that would conform to the requirements of G.O 112A. Standard Practice 1604, section 30 states "[t]he copy of the Strength Test Pressure Report filed with the completed foreman's copy of the estimate shall be retained for the life of the facility."[134]

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[130] PG&E response to DR 4 Q5-6, PG&E repeats this response for several time frames in Table 2A-2 of its June 20, 2011 filing.

[131] Response to DR 4 Q 5-6.

[132] Response to DR 18 Q 8 Attachment 1.

[133] Response to DR 1 Q 17.

[134] Response to DR 18 Q 8 Attachment 1.

Standard Practice 1604 was updated in 1970 and renamed A-34, Drawing Number 087712.[135] The 1983 A-34 policy cites 49 CFR 192.101 and 192.501, in addition to CPUC GO 112. Section 25 of Standard Practice A-34 requires that "a chart record shall be made of the pressure test for all lines or systems being uprated and for new or reinstated facilities to operate at or over 30% Specified Minimum Yield Strength (SMYS)," then specifies the information, including the pipe design specifications, to be recorded on the back of the chart. Standard Practice 1604, section 25.1 of Standard Practice A-34 states that "The original of the test chart is to be attached to the original of the Test Report Form 62-4921. A copy of the test chart is to be attached to each copy of the test report. This record is to be retained for the life of the facility."[136] PG&E's latest Standard Practice A-34 policy is dated 2003 and still includes a record retention clause with wording similar to that of the 1983 version requiring the record to be retained for the life of the facility.[137] Unfortunately, many of these records were not retained – a loss of information critical to the accuracy of an integrity management risk assessment model and vital to the safe operation of PG&E's pipelines.

4.4. Weld Maps and Inspection Records Mostly Missing or Incomplete

In October 1963, PG&E developed a Standard Practice to "establish a minimum weld check by radiographic or visual examination procedures on all gas piping systems, in accordance with General Order 112".[138] In this same Standard Practice, PG&E's records retention policy calls for retaining weld inspection reports for the life of the facility.[139] However, in practice, PG&E does not retain x-ray films beyond about 5 years.[140] And, despite PG&E's policies to create and manage weld records, few weld records can be found in PG&E Job Files. The weld records that are found are generally copies of weld inspection logs that were prepared for an inspection but were never completed with the inspection results.[141]

[135] PG&E's practice until just recently was to formalize some of its attachments to standard practice documents as "drawings" using the same title blocks, signature block, dating and version numbering as used on facility drawings. Thus, sometimes these records are referred to by drawing numbers instead of attachments to a Standard Practice.

[136] Response to DR 18 Q8 Attachment 6 (1983), also P2-939 (1986).

[137] Response to DR 18 Q 8 Attachment 14 (2003).

[138] P2-1286, SP 1605.

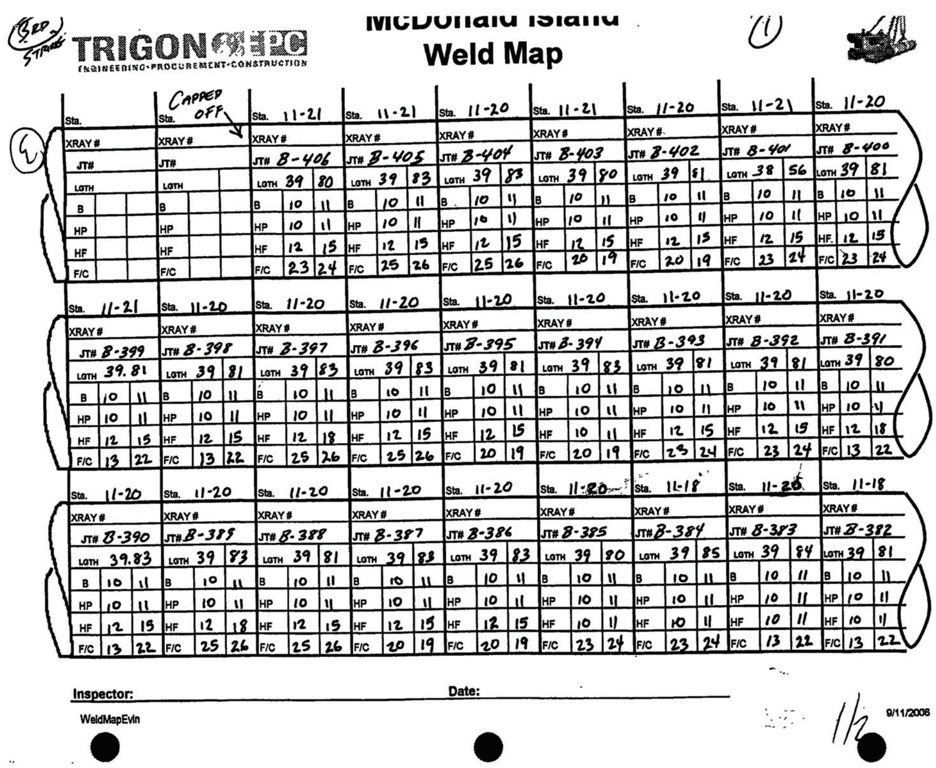
[139] P2-1286, SP 1605.

[140] Based on discussion with PG&E in Rocklin Office when viewing X-Ray films stored at that location.

[141] From review of ECTS records.

Weld maps and inspection records for PG&E's transmission pipelines, which would normally be a source of key pipeline data for the integrity management risk assessment model, are mostly missing.[142]

The maps generated during a construction project that show the location and orientation of welds on a pipeline are called Mainline and Tie-in Weld Maps.[143] A thorough review of many job files in PG&E's new Enterprise Compliance Tracking System database revealed very few such weld maps, even though they should have been retained in the master Job File according to PG&E' policies.[144] These missing weld maps would provide invaluable information to PG&E in its current efforts to locate and evaluate welds.



Sta.			11-21	11-21	11-20	11-21	11-20	11-21	11-20
XRAY #									
JT#			B-406	B-405	B-404	B-403	B-402	B-401	B-400
LGTH			39 80	39 83	39 83	39 80	39 81	38 56	39 81
B			10 11	10 11	10 11	10 11	10 11	10 11	10 11
HP			10 11	10 11	10 11	10 11	10 11	10 11	10 11
HF			12 15	12 15	12 15	12 15	12 15	12 15	12 15
F/C			23 24	25 26	25 26	20 19	20 19	23 24	23 24

Sta.	11-21	11-20	11-20	11-20	11-20	11-20	11-20	11-20	11-20
XRAY #									
JT#	B-399	B-398	B-397	B-396	B-395	B-394	B-393	B-392	B-391
LGTH	39.81	39 81	39 83	39 83	39 81	39 83	39 81	39 81	39 80
B	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11
HP	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11
HF	12 15	12 15	12 18	12 15	12 15	10 11	12 15	12 15	12 18
F/C	13 22	13 22	25 26	25 26	20 19	20 19	23 24	23 24	13 22

Sta.	11-20	11-20	11-20	11-20	11-20	11-20	11-18	11-20	11-18
XRAY #									
JT#	B-390	B-389	B-388	B-387	B-386	B-385	B-384	B-383	B-382
LGTH	39.83	39 83	39 81	39 83	39 83	39 80	39 85	39 84	39 81
B	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11
HP	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11
HF	12 15	12 18	12 15	12 15	12 15	10 11	10 11	10 11	10 11
F/C	13 22	25 26	25 26	20 19	20 19	23 24	23 24	13 22	13 22

Inspector: Date:

WeldMapEvin 1/2 9/11/2006

Figure 4[145]

[142] Response to DR 14 Q1.

[143] Response to DR 14 Q1 Attachment 1 & 3.

[144] Response to DR 15 Q 6 – ASME/ASA B31.1.8 and API 1104.

[145] Response to DR 14 Q 1 Attachment 2.

In addition to weld maps, inspection reports are an important source of information about the quality of welds. However, PG&E has not retained very many weld inspection reports. Records of weld inspections might be found in the construction engineer's field notes taken daily by the engineer overseeing a project in the field. PG&E's policies do not require the inclusion of field notes in the master Job File. In fact, it seems they are not necessarily included in the personal job files either, but may be kept in various types of notebooks or log books at the preference of each engineer. Some Job Files in the Enterprise Compliance Tracking System database include field notes, but most do not. When asked to produce field notes, PG&E responded that it could not locate field notes for a specific list of pipelines.[146] PG&E states that "[i]nformation contained in the documents provided by field engineers is typically transferred to appropriate forms and records used by PG&E to document its facilities. PG&E does not (and has not to the best of its knowledge) maintain a formal recordkeeping practice relating to field engineer notes."[147]

The importance of weld inspection records is illustrated by reviewing the weld inspection report found for the 1948 installation of Line 132 from Crystal Springs to the Martin Station (Job File Number 98015). This report shows a number of longitudinal and circumferential welds that were cracked or that contained anomalies or inclusions. Some of the welds were repaired. Other circumferential and longitudinal welds, characterized as sloppy, containing gas pockets, and inclusions, were checked off as accepted, allowing the pipe with defective welds to remain installed in the transmission system.[148] Only 10 % of the welds in the line were x-rayed, so there is no way to determine how many additional welds in the pipe that was installed in that project were also bad. Sections of that pipeline were subsequently replaced when the line was relocated to make way for various development projects during the period 1950-1985.[149] In most instances, the pipe that was replaced was salvaged.[150] Any of the pipe that was salvaged may have included some bad welds. PG&E reused the salvaged pipe on other projects but did not

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[146] Response to DR 17 Q 1 and Response to DR 17 Q 1 Attachment 1.

[147] Response to DR 17 Q 1.

[148] PG&E ECTS documents MAOP05400964, MAOP05400966, MAOP05400967, MAOP05400970, MAOP05400971, MAOP05400980, MAOP05400987 and Response to CPSD 194 Q 11 Attach. 1.

[149] Response to DR 7 Q 12.

[150] Based on the author's review of thousands of historical documents in PG&E's ECTS database.

keep track of where the pipe was reused in the system.[151] Apparently, the weld records did not accompany the salvaged pipe. PG&E has never had a formal policy or practice of inspecting the welds in salvaged pipe before it is reused.[152]

There is very little weld data in the current integrity management risk assessment model for most pipeline segments because PG&E did not keep the records and any records that may exist cannot be found.[153] As mentioned in Section 3.0 of this report, there are several data fields for weld data built into the integrity management risk assessment model. Unfortunately, due to the lack of data, there are no entries for weld data for many pipeline segments.[154]

4.5 Many Operating Pressure Records Missing, Incomplete or Inaccessible

The operating pressure history over the life of the pipe is a critical record for any piping, including natural gas pipelines. This record should keep track of normal operating cycles showing high and low pressures as evidence of the pressures to which the piping is subjected under normal operating conditions. The highest pressure and durations at that pressure over specified periods (for instance, daily, weekly, or monthly) should always be recorded because they will be used by engineers to analyze such things as the condition of the pipe and welds (especially those known to have a manufacturing threat such as Electric Resistance Welded Pipe),[155] any risk associated with continued operation at routine pressures, the possibility of uprating to a higher MAOP, the risk of failure, or the expected life of the pipe. In assessing corrosion risk relative to the expected life of the pipe (a pipe wall made thin by corrosion could leak under normal operating pressure), PG&E recognizes the importance of pipeline operating pressures in its Risk Management Procedure, noting that the pipeline operating pressures are "required" for risk assessment and stating that significant changes in pressure may trigger new

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[151] See Section 4.7 of this report for more discussion about salvaged and reused pipe.

[152] Response to DR 3 Q 10, but see 1988 Memo Response to DR 10 Q 5 Attachment 6.

[153] For example, in response to DR15 Q6 PG&E admits that with respect to the 1956 installation of Segment 180, it has not located pressure test or x-ray documentation, standard tests to prove the integrity of welds when they are completed on an installation project.

[154] An additional source of weld quality data is technical reports resulting from metallurgical analysis of pipe welds that are either suspect or that failed. PG&E performs these analyses at its San Ramon ATS facility and also contracts out to various labs. The records experts for this OII, Paul Duller and Alison North estimate that approximately 17 % (13,228) of the analytical investigation reports are missing.

[155] P3-27410, p. 2, Define manufacturing threat.

DG-ICDA regions.[156] The same pressure history recordkeeping is crucial to other considerations (e.g. weld integrity) of integrity management as well.

PG&E keeps some pressure excursion information in abnormal incident reports, but these reports appear to stand alone, and are not integrated into any particular historical record of operating pressures.[157] Pressure history recorded in SCADA began in 1986, but records are probably only readily accessible back to 2003, when the SCADA system was upgraded to the current program.[158] Generally, PG&E has no "life of the plant" record of operating pressures for the life of its pipelines. Moreover, PG&E acknowledged that it recently lost pressure records for all of 1999 for all pipelines in its system.

> "In 2004, Gas Operations migrated the data base used to capture SCADA pressure records from an (sic) the existing server to a more powerful server (the Ascon server). The process of migrating the records to the Ascon server required using back-up tapes of SCADA records from prior years, as the existing server did not contain a historian function that permitted storage of and access to pressure records from prior years. During that migration process, the Gas Control ISTS team building the new database discovered that the back-up tape for 1999 did not contain the 1999 pressure records data. The team did not know the circumstances accounting for why the 1999 back-up tape did not contain the data. They tested the tape to see whether the data was on the tape in a corrupted form that perhaps could be recovered, but the tape did not contain the data. As a result, the new database does not have historic pressure records from 1999 for any PG&E pipelines."[159]

Because of this loss of one year of pressure records, PG&E simply cannot give an accurate accounting of pressure excursions above MAOP for any pipeline in its system, which means the company cannot accurately assess the condition of any of its pipelines.

PG&E does not have the historical operating pressure records needed for its integrity management risk assessment models. Because these pressure records are required elements for the integrity management risk assessment models, PG&E must enter a number into the model for each pipeline segment, whether or not there is a factual basis for the pressure selected.

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[156] P2-390, p. 26, DG-IGDA is Internal Corrosion Direct Assessment for a Dry Gas pipeline.

[157] Response to DR 7 Q 1, Abnormal Incident Reports

[158] Response to DR 4 Q 9.

[159] Response to DR 15 Q 10.

Obviously, entering an incorrect pressure will contribute to an inaccurate risk ranking of pipeline segments by the model.

4.6 Leak Records Incomplete, Disorganized and Inaccessible

PG&E has failed to maintain leak records in a manner that makes the information readily accessible and states that it cannot retrieve leak data prior to 1970. Yet, PG&E also says 20 percent of its lines were installed prior to 1970.[160] Information about past leaks in existing pipelines is a category of data fundamental to predicting likely leaks in those pipelines in the future. The probability model needs "cause of leak" data to complete the risk calculations in the model.[161] For pipelines that have not had a post construction pressure test, it is essential that the number and type of leaks on that pipeline and similar pipelines are known. If such data is not available or is suspect, then the stability of the pipeline with regard to materials and construction threats cannot be determined since leak data is critical to determining stability.

A review of PG&E's various forms (all referred to as "A-Forms") used to collect leak information reveals inconsistent reporting, incomplete reports and poor follow up. "For instance, in 2006, integrity management staff documented 13 leaks in line 132 between 1964 and 1988 based on A-forms. Of the 13 leaks identified, PG&E could determine the cause of only 1 leak because no cause was documented on the A-forms for the other 12 leaks".[162] Without a documented cause, it would be impossible to assign the leaks to the model in the appropriate data fields for calculation of likelihood of failure due to corrosion, third party, ground movement, weld quality, etc. Over the years, the data has been stored in binders at local offices, in engineering offices, and in various databases. Once the data was uploaded to databases, PG&E found that it was unable to include the historical data from one database to the next and thus ended up with at least three different databases containing different sets of leak data, in addition to paper records. As a result of this disorganization of basic leak records, PG&E has been unable to respond to requests in this investigation to produce lists, counts, and characteristics of past leaks on particular pipelines.[163]

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[160] Response to DR 42 Q 7 ((1076 miles*100)/5324 miles = 20%).

[161] 1984 Bechtel Report. The Bechtel models and reports are discussed in Section 3.0.

[162] P3-24119 p. 9.

[163] Response to DR 40 Q 3.

Although they are the primary record regarding leaks, PG&E's A-Form reports are poorly managed, inconsistent, and incomplete. Leaks reported from leak surveys, employees, and third parties are reported on A-Forms. The leaks are graded from 1 to 4, with grade 1 being the most critical, requiring immediate attention. Grade 3 and 4 leaks can remain in the system, unattended for months, even years. These leaks are monitored for a change in grade. In the records, it appears some of these leaks "disappear" after subsequent surface testing reveals no reading on a test instrument.[164] As of November 10, 2011, PG&E reported for its transmission lines no active Grade 1 leaks, 16 active Grade 2 leaks, 145 active Grade 3 leaks and 609 Grade 4 leaks.[165] The records for these leaks are kept in the integrated gas information system database which is the current database that contains A-Form information.[166] The A-Forms are filed in notebooks in the division offices.

A review of A-Forms that PG&E collected from the regional offices and from various other records files and produced in this proceeding reveals that the A-Forms program has been poorly managed. These forms have changed over time so that the historical record is inconsistent. Plus, the A-Form is designed for multiple purposes and uses. For instance, the person who initially reports the leak may fill out one part of the form. A person who goes out and rechecks the leak must find the original form and fill out the next part of the same form. A person who digs up the leak and repairs it will fill out yet another part of the form. PG&E explains as follows:

> "PG&E's Leak Repair, Inspection, and Gas Quarterly Incident Report (also referred as an "A-Form") typically constitutes PG&E's field report of observed conditions relevant to gas transmission leaks, including leaks on welds. This document is filled out by field personnel responsible for leak detection, inspection, and repair. Over time, the form has evolved to call for field employees to gather a substantial amount of data including pipe specifications, soil type, cathodic protection, and external pipe condition. The form also calls for determination of leak source and leak cause. PG&E produced the earliest-located revision of this document (dating back to 1979) in the June 20, 2011 OII response as attachment P2-1152. Physical copies of A-Forms are

[164] Example A-Forms are provided as Appendix 5 to this report.

[165] Response to DR 23 Q 16.

[166] PG&E states that leaks from the IGIS database are mapped to pipelines in the GIS mapping system, but admits that the mapped location of each leak is not accurate.

> maintained locally in the gas division and district offices responsible for the gas facility that led to creation of the A-Form, as well as in gas transmission and distribution mapping offices. A-Forms are organized in varying fashion across offices. Some local offices organize A-Forms by date. Others organize A-Forms by geographic location (wall map and plat). In some instances, such as where an A-Form is associated with a construction project, the A-Form may be in a job file. Since approximately 1970, electronic records of A-Forms have been created and stored in PG&E's electronic leak databases. PG&E's policy is to maintain hard copy A-Forms for the life of the facility."[167]

The risks of allowing leaks to go unattended include exposing people to harmful gas, the potential for explosions where gas accumulates in closed areas, and total pipe failures resulting in catastrophic damage like the San Bruno pipe failure in September 2010. Every company that transports natural gas through pipelines must have an active leak detection program to protect the public. PG&E has had a leak detection program since at least 1958.[168] Unfortunately, even though it had a leak detection program in place, it failed to document and save the data in a way that made the data retrievable.

The A-Form is one of PG&E's oldest record systems. However, A-Forms are frequently only partially completed, even within the portion to be filled out by any one individual.[169] Further, leaks are rarely graded on the A-Form, which begs the question of how a grade is ultimately assigned, and who makes that decision when the leak information is entered into a database. For these reasons, A-Forms are an incomplete record of leaks and the ones that do exist are difficult to use as a resource of leak data for the integrity management program.

PG&E says that it maintains leak records for the life of the facility, plus 6 years (later revised to Life of Facility in records retention plans).[170] But, when asked if it could simply count the total number of leaks that it has had on each transmission line since installation, PG&E responded that it could not, stating:

> "No. PG&E believes that taken together its leak records and databases contain information about substantially all leaks on the gas transmission system. However, the records are not fully

[167] Response to DR 4 Q 12.

[168] P2-1149, Standard Procedure 460.21-4, 1966 – indicates it replaced a 1958 version.

[169] See Appendix 5 to this report.

[170] P2-2, 2010.

> integrated, making it difficult to count the total number of leaks across the entire transmission system."[171]

In light of the earlier discussion citing Bechtel's conclusion that leak information is one of the most important sources of information for integrity management, the inability to find leak records for each transmission line raises serious safety concerns. The history of leaks caused by corrosion is also an important component of PG&E's integrity management program, yet PG&E effectively has no means to track the history of corrosion in any particular pipeline segment or to accurately and meaningfully incorporate that history into integrity management. Since leak data is another essential element of the integrity management risk assessment model, the lack of this data renders the model useless in accurately calculating likelihood of failure for any specific pipeline segment.

4.7 No Tracking System for Salvaged and Reused Pipe

Over the years, PG&E moved pipe (often in service for many years) from one location to another within its system but did not keep track of where the pipe was reinstalled in the transmission system, making it now impossible to accurately determine the age of pipe in any segment.

In 1957, PG&E commented on the Commission's proposed General Order:

> "These paragraphs stipulate that no used pipe or pipe of unknown specification should be used at pressures exceeding 300 psig. The American Standard Code details complete and adequate procedures to be followed to qualify such materials for use and to insure that safe installations result. It has been Company experience that pipe salvaged from gas lines in service for many years under severe conditions is in general good pipe. With proper inspection, repair and test, re-use of this material should be permitted. The staff's draft does not consider the effect of the actual working stress in connection with re-used pipe. The 300 psig pressure limit is arbitrary in that it fails to take into consideration the thickness of such pipe. For example, salvaged 16" x 1/2" wall thickness pipe could not be used for a 300 psig operating pressure even though the steel stress would be only 4800 psig. On the other hand, 16" x 1/4" salvaged pipe could be used for a 299 psig pressure although the steel stress would be 9568 psig."[172]

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[171] Response to DR 40 Q2.

[172] Response to DR_033-Q10, Atach 2, p. 3.

According to this comment PG&E believed that it was acceptable to re-use pipe, but also stated that proper inspection, repair and testing was required prior to re-use. However, PG&E never implemented such a program.[173]

In the process of reviewing PG&E records it has become apparent that PG&E has salvaged and reused transmission pipe now operating in its system that may not be satisfactory for continued service. This conclusion is based on weld radiography reports that show acceptance of marginal and bad welds on pipe that was subsequently salvaged and sent to the company storage yard for reuse elsewhere in the system. PG&E has a practice of salvaging pipe when it is removed from the ground, for instance when a highway or development project requires the relocation of a gas transmission line.[174] This practice has apparently always existed within PG&E, although, PG&E currently requires pipeline materials to satisfy specifications and standards set forth in its own Standards A-16 and A-34, and currently has a policy that prohibits the installation of reconditioned or used transmission pipeline fittings, such as elbow, tees, reducers and caps.[175] Reusing pipe is an acceptable practice as long as the salvaged pipe is inspected and tested as necessary to confirm the integrity of the pipe for reuse within the design requirements for the new installation.[176] However, even if it is inspected, it would always be prudent to keep track of where the older pipe is within the system in case an issue arises later related to the earlier fabrication of the pipe or prior abnormal operating events involving the pipe.

PG&E states that it never has had policies to track salvaged, reused and/or reconditioned pipe within its system.[177] Yet, it appears that PG&E's early accounting and engineering

[173] Response to DR 16, Q1; Response to DR 10 Q 5 and DR 10 Q 2.

[174] As evidenced on numerous project face sheets, accounting documents that record authorization and completion of projects. The forms used include a section for recording the amount of pipe salvaged so that the value of the salvaged pipe can be credited to the appropriate account. Example Face Sheet showing salvage – See Appendix 7 to this report.

[175] Response to DR 10 Q5 and DR 10 Q5, Attachment 3.

[176] For instance, PG&E had a special inspection process for A.O. Smith pipe that was initially installed in the 1920s-30s as "PG&E Spec Pipe", then later salvaged and reused in the 1950's – 60's. Response to DR 10 Q 5 Attachment 06.

[177] Response to DR 16, Q1; Response to DR 10 Q 5 and DR 10 Q 2. Note: In response to DR 10 Q 2, PG&E states that salvaged is synonymous with reconditioned (as opposed to "salvaged" meaning scrapped or junked).

documents did keep track of salvaged and reused pipe.[178] For instance, there are some construction drawings that include notes about pipe having been salvaged and abandoned, and about small pieces of pipe having been welded together at Milpitas Storage Area before being delivered to a construction site.[179] A review of records in Job files reveals various types of accounting documents and notes on project documents and construction drawings that show the salvaging, reconditioning and abandoning of pipe. Some historical details in Job Files suggest that PG&E once had this tracking capability because there are notes on project face sheets stating that pipe is to be salvaged or abandoned and also stating the original installation project and date of the pipe.[180] At some time in the past, PG&E apparently lost track of these records. In fact, after months of its own research, PG&E pieced together the potential sources of pipe that went into the 1956 construction of Line 132, Segment 180 that failed in San Bruno. These records reveal that most of the pipe was salvaged and reconditioned from other pipelines in the PG&E system, but they do not identify the previous locations of the pipe, or its age.[181] (Figure 5)

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[178] Based on review of thousands of records in the ECTS database.

[179] Response to DR 24 Q 1 & Q 2, Response to DR 7 Q 12 Attachment 4.

[180] See example at Appendix 6 to this report.

[181] Figure 5 - From Response to NTSB Exhibit 2-DV. File #460235.

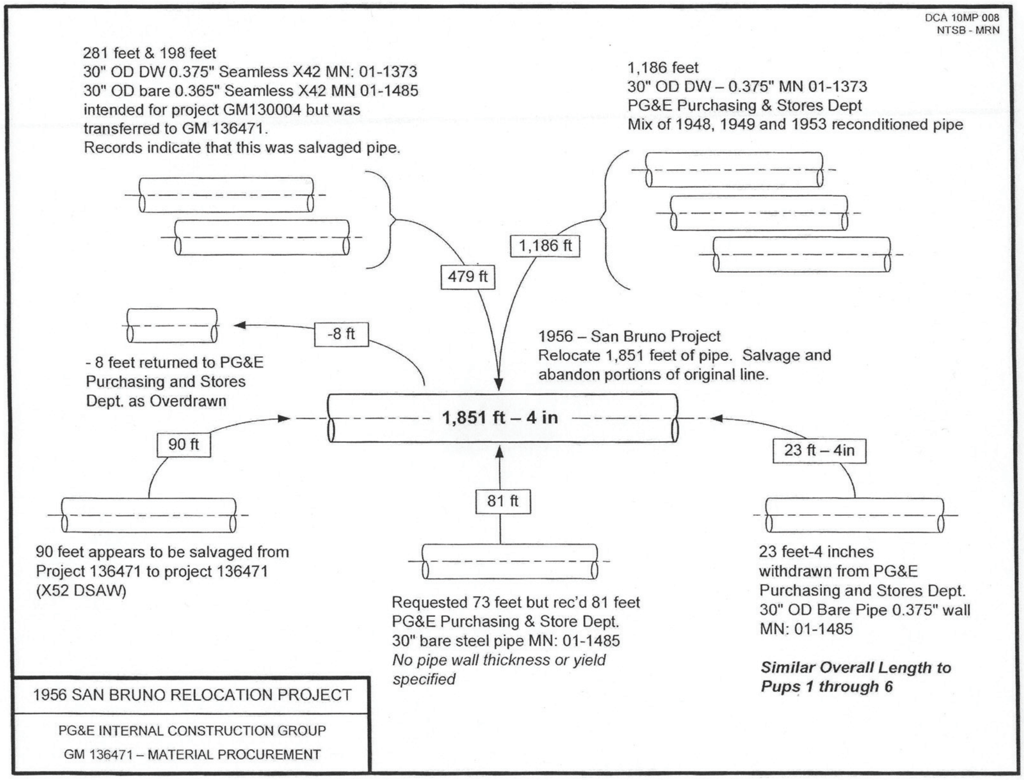

Figure 5[182]

In 1979, in what appears to be an intentional effort to eliminate records that show the use of salvaged pipe, PG&E's drafting instructions in Mapping Standards 410.21-1, section II.3, states "salvaged and abandoned mains – to be removed from plat sheets." The instructions offered no additional explanation as to why the information should be removed.[183] Generally, based on reviewing thousands of documents in the Enterprise Compliance Tracking System (ECTS) database, it appears that sometime in the 1980's PG&E lost the ability to track salvaged pipe.

It seems likely that if PG&E had maintained its accounting records for capital investments over the life of the facilities as it should have, in accordance with regulations and

[182] NTSB_460235, NTSB Docket No. SA-534, Exhibit No. 2-DV. Note: This figure shows that 281' and 198' of seamless pipe was used, making this document one more PG&E record that is inaccurate since 30" seamless pipe was never manufactured.

[183] P2-323, p. 16

general accounting principles, it now would have a detailed record that could be used to track salvaged pipe to reconditioning and reinstallation in another project.[184]

During this proceeding, CPSD disclosed records discovered in the ECTS database showing that PG&E salvaged and reused pipe from Line 132 that had been documented during original construction in 1948 as having bad welds.[185] It is impossible to determine where this salvaged pipe ended up in the system. After the disclosure, PG&E attempted to track these pieces of salvaged pipe but was largely unsuccessful. In its response dated November 15, 2011, PG&E repeatedly stated "[a]s part of PG&E's MAOP validation project, reconditioned pipe currently installed in the gas transmission system is being catalogued and tracked."[186] In fact, a column for reconditioned/salvaged pipe was added to PG&E's pipeline features list (PFL) spreadsheet on September 1, 2011.[187] By that time, over 2.2 million Job File documents had already been scanned into the ECTS database, viewed and catalogued.[188] Most of the records identified during this investigation by CPSD were found during random checks of pages of Job Files listed in PG&E's ECTS "non-Pipeline Features List" category. To find and add all of the relevant pages to the Pipeline Features List, someone would have to find the documents in ECTS and catalog them – not an easy task when there are millions of pages that were scanned in as unsearchable images. To find the salvaged pipe in PG&E's system, each page of ECTS must be individually opened and viewed.

PG&E's new program of implementing a tracking system to identify and track reconditioned and salvaged pipe is an effort to address the deficit in its previous recordkeeping programs. Unfortunately, the great amount of time it will take to identify and account for used pipe in the system could be punctuated by additional pipe failures. And, even if the pipe is located, PG&E still must figure out when it was originally purchased, what its design characteristics are, and the service conditions it was exposed to over time. Because PG&E has moved pipe from one location to another within its system without keeping track of where the

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184 Response to DR 33 Q 1, Attachment 1 1938 Records Retention Schedule.

185 Project Number GM 98015.

186 PG&E's Updated Supplemental Response to LD's "Notice and Disclosure of Safety Evidence and Companion Motion for Public Release of Evidence", I.11-02-016, filed Nov 15, 1011.

187 Response to DR 16 Q 5.

188 Response to DR 39 Q1.

pipe went, it is now difficult to state in the integrity management risk assessment model the age of pipe in any pipeline segment.

Finally, the loss of records about the location of salvaged pipe means PG&E cannot determine that pipe specifications data entered into its integrity management risk assessment model is accurate for every pipe segment. This uncertainty creates an ongoing safety risk associated with using the integrity management risk assessment model to prioritize pipe projects based on likelihood of failure or highest risk.

5.0 BAD DATA IN THE GEOGRAPHIC INFORMATION SYSTEM

PG&E's Geographic Information System (GIS) replaced most of PG&E's paper records for documenting facility data, but the database was populated with faulty data, including assumed and missing elements from earlier databases making it an unreliable source of data for the integrity management risk assessment models.[189] In spite of the GIS's critical importance to engineering and operations, that database cannot be more reliable than the records used to populate it. In addition, its usefulness is limited because the system is populated with many blank and assumed entries.

When asked to state the number of miles of pipeline in PG&E's transmission system that have one or more assumed or unknown values in the GIS and the pipeline survey sheets, PG&E answered "approximately 5,324 miles," which is the total number of miles in service in PG&E's transmission pipeline system.[190] Indeed, PG&E produced a list showing the assumed and blank values in the GIS system for every segment of each pipeline.[191] Thus, important data for pipelines throughout PG&E's system is either assumed or unknown.

When PG&E was asked about its Quality Assurance/Quality Control (QA/QC) program related to the transition of data from hard copy records to the electronic GIS, it stated: :

> "PG&E has been unable to locate or identify any documentation or formal procedures relating to quality control and/or quality assurance of the data transfer from hardcopies to pipeline survey

[189] GSAVE, PG&E's first gas transmission GIS program, was deployed in May 1998. GSAVE was a customized program composed of scripts and tools built using ESRI's ArcInfo 7.x and ArcView 3.x software base. GSAVE was operational until November 2003. GasMap 1.0 and GasView 1.0 replaced GSAVE in November 2003. GasMap and GasView were also custom GIS applications developed by PG&E using ESRI ArcGIS 8.x software. GasMap and GasView migrated to ArcGIS version 9.x in 2005. PG&E deployed GasMap 2.0 in July 2011. GasMap2.0 is based on ArcGIS 9.3.1.

[190] Response to DR 27 Q 12 & 13.

[191] Response to DR 27 Q 12 Attachment 1 & 2.

> sheets, and from pipeline survey sheets to GIS. Given the passage of time, it is difficult for PG&E to identify what QC/QA processes may have existed."[192]

Errors in records have been carried forward from one system to the next without checks for accuracy or, in some cases even reasonableness. As stated above, PG&E has no record of a QA/QC program for the transfer of data into the GIS.[193]

6.0 RECORDS LOST IN PG&E'S ENTERPRISE COMPLIANCE TRACKING SYSTEM DATABASE

PG&E is now in the process of consolidating all of its Job Files into the Enterprise Compliance Tracking System. In ECTS, the master Job File has been combined with individual Job Files under the same job number. While the master Job File documents are identified in the database as coming from the Walnut Creek engineering library, the total number of documents in any one Job File is now so huge that it is difficult to review the records and locate critical documents. In addition, there is an excessive amount of duplication in the ECTS database, making it cumbersome to use.[194]

Since each page is scanned as a separate image document, PG&E cannot search these pages to find anything, including field notes. It would take hundreds of hours to open each page and look at it. So, for now, PG&E's Job File records are essentially lost in its own ECTS database.

7.0 CONCLUSION

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[192] Response to CPSD DR 215 Q6.

[193] For example, there is an error in GIS that comes directly from a pipeline survey sheet. QA/QC weakness appears in the GIS rendition of the pipeline survey sheet for L-132, dated 9/11/2011. In this record, PG&E shows that Segment 180 was pressure tested with gas in 1961, but admits it has not identified any records related to the 1961 gas test. However, there are no records of such a test in the Job File. PG&E responded to a request for test records that "with respect to the 1956 installation of Segment 180, PG&E has not located pressure test or x-ray documentation." PG&E believes this gas test information came from a 1968 report filed with the PUC that indicates a gas test occurred in 1961. However, careful inspection of that record finds that in 1968 PG&E reported that the piece of L-132 between MPs 39.04 and 39.37, which represent the current location of Segment 180, was installed in 1948. Thus, by 1968 PG&E had apparently already misplaced its records that showed the 1956 project relocation of Segment 180.

Response to DR 7 Q 12 Attachment 83,

Response to DR 45 Q 8 and PG&E Report June 20, 2011 p. 6D-4 and P3-30011.

[194] See Testimony of Paul Duller, Records Expert for CPSD in this proceeding.

This investigation into recordkeeping issues related to engineering results in two basic conclusions. First, the pipe failure and explosion on Line 132 in San Bruno on September 9, 2010 may have been prevented had PG&E managed its records properly over the years. And second, PG&E's entire integrity management program is an exercise in futility because PG&E lacks the basic records necessary to provide fundamental data required for the successful use of the integrity management risk model. Therefore, PG&E has been operating, and continues to operate, without a functional integrity management program.

ATTACHMENT

Margaret Felts

LITIGATION EXPERIENCE AS LEAD TECHNICAL CONSULTANT

2005-2007

LODI GROUND WATER CONTAMINATION
CLIENT: LAW FIRMS REPRESENTING
LLOYDS OF LONDON INSURANCE
COMPANIES INSURANCE, DEFENSE

2000-2002

CALIFORNIA ENERGY CRISES
ENRON INVESTIGATION
PG&E BANKRUPTCY
CLIENT: CA PUBLIC UTILITIES COMMISSION
ENERGY, PLAINTIFF
PLAYA DEL REY GAS STORAGE INTEGRITY, SOCALEDISON
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIVISION OF RATE PAYER ADVOCATES
ENERGY, PLAINTIFF

2001-2002

BELMONT PROPERTIES
CLIENT: ROPERS
ENVIRONMENTAL, DEFENSE
THREE SISTERS RANCH
CLIENTS:DUANE MORIS & TED HANIG
LAW FIRMS
ENVIRONMENTAL, DEFENSE
AEROJET & LOCKHEED CASES
CLIENTS: MORRIS POLICH & PURLLY,
BERKES, CRANE, ROBINSON & SEAL LLP
INSURANCE, DEFENSE
PG&E POWER OUTAGE, SAN FRANCISCO
DIVISION OF RATE PAYER ADVOCATES
ENERGY, PLAINTIFF

1998-2000

RAYTHEON
GROUND WATER CONTAMINATION
LAW FIRMS REPRESENTING
LLOYDS OF LONDON INSURANCE COMPANIES
INSURANCE, DEFENSE

1998-1999

PG&E TREE TRIMMING CASE
MONTEBELLO GAS STORAGE (SOCALGAS)
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF
BENZENE EXPOSURE
BARON & BUDD, P.C.
ENVIRONMENTAL, PLAINTIFF

1998-1999

CARPENTER V. CROWLEY MARITIME
BENZENE & ASBESTOS EXPOSURE
WARTNICK, CHABER, ET AL
ENVIRONMENTAL, PLAINTIFF
SCE APP NO. 97-12-043
HARBOR COGEN BUYOUT OF LONG TERM CONTRACT
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES-
ENERGY, PLAINTIFF

1997 - 2002

SKINNER V. ARCO
CLIENTS: TERRY LUMSDEN LAW FIRM
KELLER ROHRBACK L.L.P.
ENERGY/ENVIRONMENTAL, PLAINTIFF

1996-1997

SOCALGAS V. ASSOCIATED ELECTRIC GAS INSURANCE COS.
CLIENT: HANCOCK, ROTHERT & BUNSHOFT, LA
INSURANCE, DEFENSE

1997 - 1998

EXXON V. INA, SUPERFUND CLEANUP CLAIMS
CLIENT: HANCOCK, ROTHERT & BUNSHOFT, SF
INSURANCE, DEFENSE

1996 - 1997

DIXIE VALLEY POWER PARTNERSHIP
CONTRACT BUYOUT BY SCE
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

1996-2000

PROCTOR V. LOCKHEED
SOIL AND GROUNDWATER CONTAMINATION
CLIENTS: LAW FIRMS REPRESENTING
LLOYDS OF LONDON INSURANCE
COMPANIES
INSURANCE, DEFENSE

1993

TOOLEY OIL V. SNIDER
CLIENT: NAGLEY & MEREDITH, INC.
ENVIRONMENTAL, PLAINTIFF
CLAYTON RD. ASSO INC. V. TEXACO REFINING & MARKETING INC.
CLIENT: NED ROBINSON
ENVIRONMENTAL, PLAINTIFF
WALSH V. DIABLO MARINE
CLIENT: TURNER, HUGUET, BRANS & ADAMS
ENVIRONMENTAL, PLAINTIFF
TASSAJARA NURSERY V. INSURANCE CO.
CLIENT: NELSON, WARNLOF & VENCILL
INSURANCE, DEFENSE

1992

WISE/WILLIAMS V. BECHTEL
CLIENT: POTTER LAW OFFICES
TORT CASE FOR INJURIES RESULTING FROM MOHAVE POWER PLANT INCIDENT
ENERGY, PLAINTIFF
PACHECO PROPERTIES V. CHEVRON PIPELINE
CLIENT: TURNER, HUGUET, BRANS &ADAMS
ENVIRONMENTAL, PLAINTIFF
NEVADA POWER V. STATE OF NEVADA
CLIENT: STATE OF NV ATTORNEY GENERAL OFFICE OF ADVOCATE CUSTOMERS OF THE PUBLIC UTILITIES COMMISSION
ENERGY, PLAINTIFF

1991-1993

PG&E APPLICATION RE HELMS PUMPED STORAGE CLAIM
CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

1991

SALLE V. RUDD, ET AL
CLIENT: KLAUSCHIE & SHANNON
INSURANCE, DEFENSE

1990

AEROJET GENERAL CORP, ET AL V. ARGONAUT INSURANCE CO., ET AL
CLIENT: HANCOCK, ROTHERT & BUNSHOFT
INSURANCE, DEFENSE

1988 - 1992

SCE APPLICATION RE MOHAVE COAL FIRED PLANT STEAM PIPE FAILURE
CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

1987-1988

SOCALGAS APPLICATION - CONTRACT
BUYOUT RE MONTEREY LAND PARK LANDFILL GAS
(OPERATING INDUSTRIES)
CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES
ENERGY / ENVIRONMENTAL, PLAINTIFF

1986

SOCALGAS V. FORD, BACON & DAVIS
CLIENT: LAW FIRM REPRESENTING FORD, BACON & DAVIS
ENERGY, PLAINTIFF

1985

US OF A BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION RE PACIFIC OFFSHORE PIPELINE COMPANY, DOCKET NO. RP85-34-000
CLIENT: CA PUBLIC UTILITIES COMMISSION
ENERGY, PLAINTIFF

1983 - 1985

SOCALGAS, APP NO. 84-09-022 RE PACIFIC OFFSHORE PIPELINE COMPANY (POPCO) GAS TREATMENT PLANT
CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

CAREER HISTORY AND HIGHLIGHTS

PRESIDENT / CFO 2002-2010

CALIFORNIA COMMUNICATIONS ASSOCIATION, WWW.CALCOM.WS, THE TRADE ASSOCIATION FOR THE INCUMBENT LOCAL EXCHANGE CARRIERS SERVING CALIFORNIA (FROM AT&T TO THE SMALLEST INDEPENDENT RURAL COMPANIES). IN THIS CAPACITY, I ALSO SERVE AS A VOTING MEMBER ON THE CA HIGH TECH CRIME ADVISORY COMMITTEE, AS DEFINED IN CALIFORNIA STATUTE.

SENIOR CONSULTANT 1995-1997

DAMES & MOORE LEAD CONSULTANT ON SEVERAL MAJOR ENVIRONMENTAL PROJECTS IN CALIFORNIA AND WASHINGTON.

DEPUTY DIRECTOR 1993-1995

CALIFORNIA DEPARTMENT OF TOXIC SUBSTANCES CONTROL DIRECTED OVERSIGHT OF ALL STATE -LEAD NATIONAL PRIORITIES LIST SITE CLEANUPS IN CALIFORNIA, AND OVER 2,000 STATE LISTED PROJECTS. MANAGED A BUDGET OF $326 MILLION, SUCCESSFULLY REORGANIZED AND COMPLETED HIRING FOR A PROGRAM WITH 312 EMPLOYEES IN 7 CALIFORNIA OFFICE LOCATIONS IN JUST 1 ½ YEARS. REDUCED OVERHEAD COSTS AND DRAMATICALLY IMPROVED SERVICE. ADDRESSED CRITICAL ISSUES AND DEVELOPED NEW PROGRAM POLICIES IN FULL COORDINATION WITH THE SITE MITIGATION PROGRAM ADVISORY GROUP, A GROUP MADE UP OF EXTERNAL INDUSTRY, ENVIRONMENTAL, AND REGULATORY REPRESENTATIVES.

DIVISION CHIEF OF ENGINEERING 1985-1990

DEPARTMENT OF DEFENSE, MCCLELLAN AIR FORCE BASE

DESIGNED AND MANAGED DOD'S FIRST PROGRAM TO IMPLEMENT CERCLA AND THE RESOURCE CONSERVATION RECOVERY ACT. SUPERVISED 15 ENGINEERS AND TECHNICAL SUPPORT PEOPLE RESPONSIBLE FOR MANAGING ALL NON-CERCLA ENVIRONMENTAL LAWS AND REGULATIONS APPLICABLE TO THE BASE, WHICH WAS A LARGE INDUSTRIAL COMPLEX EMPLOYING 12,000 CIVILIANS AND MILITARY PERSONNEL. MANAGED ENVIRONMENTAL PROGRAM BUDGET OF OVER $26 MILLION ANNUALLY.

PREVIOUS EXPERIENCE

ENVIORNMENTAL CONTRACTOR

ENERGY SPECIALIST, CALIFORNIA ENERGY COMMISSION

PROCESS ENGINEER, CELANESE PLASTICS AND SPECIALTIES

PROCESS ENGINEER, AMOCO OIL COMPANY

EDUCATION

JD, MCGEORGE SCHOOL OF LAW

M.S. ENERGY/ENVIRONMENTAL ENGINEERING, LASALLE UNIVERSITY

B.S. PETROLEUM ENGINEERING, LOUISIANA TECH UNIVERSITY

B.A. BUSINESS COMMUNICATIONS, ECKERD COLLEGE

ADDITIONAL INFORMATION

WASHINGTON STATE BAR # 40507

PHI DELTA PHI INTERNATIONAL LEGAL FRATERNITY

ASSOCIATE MEMBER, CALIFORNIA BAR ASSOCIATION

MEMBER, AMERICAN BAR ASSOCIATION

MEMBER, SOCIETY OF PETROLEUM ENGINEERS

NREP REGISTERED ENVIRONMENTAL MANAGER #2935

CALIFORNIA GENERAL A CONTRACTOR #757976